PUBLIC UTILITY REGULATORY POLICIES ACT AMENDMENTS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY REGULATION

OF THE

COMMITTEE ON

ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

NINETY-SEVENTH CONGRESS

SECOND SESSION

ON

S. 1885

A BILL TO AMEND THE FEDERAL POWER ACT AND THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 TO PLACE ELECTRIC UTILITIES, INCLUDING MEMBERS OF REGISTERED HOLDING COMPANY SYSTEMS, ON THE SAME BASIS AS NONUTILITIES WITH RESPECT TO ENCOURAGING THEIR INVESTMENT IN COGENERATION AND SMALL POWER PRODUCTION FACILITIES, AND FOR OTHER PURPOSES

S. 1966

A BILL TO ELIMINATE UNNECESSARY PAPERWORK AND REPORTING REQUIREMENTS CONTAINED IN THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

APRIL 19, 1982

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CONTENTS

Page
S. 1885 3
S. 1966 5

STATEMENTS

Brown, Peter W., director, Energy Law Institute 181
Butler, Hon. C. M., Chairman, Federal Energy Regulatory Commission; accompanied by Charles Moore, General Counsel, and Robert Means, Director, Office Regulatory Analysis 30
Chiles, Hon. J. Hunter, III, Director, Office of Policy, Planning and Analysis, Department of Energy 7
Greenman, Frederic E., vice president and associate general counsel, New England Power Co 68
Humphrey, Hon. Gordon J., a U.S. Senator from the State of New Hampshire 1
Jamison, Robert L., manager, external energy affairs, Weyerhaeuser Co., on behalf of the Council of Industrial Boiler Owners; accompanied by Earle H. O'Donnell, attorney 154
Mitchell, Ralph C., III, vice president, Conservation and Renewable Resources, Arkansas Power & Light Co 66
Nicholson, William J., manager, Corporate Energy Service, Potlach Corp., accompanied by Rigdon H. Boykin, Chadbourne, Parke, Whitside & Wolff 135
Schaeffer, Stephen C., manager, rates and research, Houston Lighting & Power Co 69
Shanaman, Susan M., chairman, Pennsylvania Public Utility Commission 47
Zimmer, Michael J., Washington counsel, Cogeneration Coalition, Inc 167

APPENDIXES

Appendix I

Responses to additional committee questions 211

Appendix II

Additional and supplemental statements submitted for the record 315

PUBLIC UTILITY REGULATORY POLICIES ACT AMENDMENTS

MONDAY, APRIL 19, 1982

U.S. Senate,
Subcommittee on Energy Regulation,
Committee on Energy and Natural Resources,
Washington, D.C.

The subcommittee met, pursuant to notice, at 10 a.m., in room 3110, Dirksen Office Building, Hon. Gordon J. Humphrey, presiding.

Present: Senator Humphrey.

Also present: Marilyn Burkhardt, counsel; Howard Useem, professional staff member; Elizabeth Moler, counsel for the minority; Benjamin S. Cooper, professional staff member for the minority; and James T. Bruce, counsel for the minority.

OPENING STATEMENT OF HON. GORDON J. HUMPHREY, A U.S. SENATOR FROM THE STATE OF NEW HAMPSHIRE

Senator Humphrey. Good morning. This subcommittee meets today to consider two bills. The first is S. 1885, a bill to amend the Federal Power Act and the Public Utility Regulatory Policies Act to place electric utilities, including members of registered holding companies, on the same basis as nonutilities with respect to encouraging their investment in cogeneration and small power production.

The second bill, S. 1966, introduced by Senator Danforth, would amend PURPA to eliminate paperwork and reporting requirements under section 116 of that act.

Before proceeding to our first panel of witnesses, I would like to make a few introductory comments with respect to S. 1885 and title II of PURPA more generally. Under FERC rules implementing title II of PURPA, electric utilities are precluded from owning more than a 50 percent equity interest in cogeneration or small power production facilities which qualify for the regulatory exemptions and rate incentives provided under that Title.

S. 1885 seeks to eliminate this ownership limitation, thus putting electric utilities on the same footing in the marketplace as nonutilities with respect to their investment in efficient and renewable energy technologies. I think all of us here today have to agree that the most basic reason for the enactment of title II of PURPA was the perceived—and I believe real—need to encourage these technologies. This bill would simply extend the notion that it is the nature of the power production facility, rather than its ownership per se, which should be the basis for encouragement under PURPA.

I know that the recent developments in the American Electric Power Case before the D.C. Circuit Court of Appeals has cast a long shadow of doubt over the future of title II of PURPA. Combined with the pending U.S. Supreme Court decision in the Mississippi case, this has caused a great deal of uncertainty in the marketplace.

Thus, while I would hope that the main thrust of today's testimony is focused on the two bills before us, I am also interested in each witness's comments on where we go from here.

Because of the length of the witness list this morning, I would like to establish the ground rule that each witness summarize his testimony in not more than 5 to 7 minutes. The full written statement will be included in the record. This will give the committee more time to ask individual questions.

With that, we will turn to our first witness, Mr. J. Hunter Chiles III, Director of Office of Policy, Planning and Analysis.

[The text of S. 1885 and S. 1966 follow:]

97TH CONGRESS
1ST SESSION

S. 1885

To amend the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 to place electric utilities, including members of registered holding company systems, on the same basis as nonutilities with respect to encouraging their investment in cogeneration and small power production facilities, and for other purposes.

IN THE SENATE OF THE UNITED STATES

NOVEMBER 23 (legislative day, NOVEMBER 2), 1981

Mr. HUMPHREY (for himself and Mr. JOHNSTON) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To amend the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 to place electric utilities, including members of registered holding company systems, on the same basis as nonutilities with respect to encouraging their investment in cogeneration and small power production facilities, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

AMENDMENTS TO THE FEDERAL POWER ACT

SECTION 1. (a) QUALIFYING SMALL POWER PRODUCERS.—Section 3(17)(C) of the Federal Power Act is amended to read as follows:

"(C) 'qualifying small power production facility' means a small power production facility which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe.".

(b) DEFINITION OF QUALIFYING COGENERATORS.—Section 3(18)(B) of the Federal Power Act is amended to read as follows:

"(B) 'qualifying cogeneration facility' means a cogeneration facility which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe.".

AMENDMENT TO PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

SEC. 2. Section 210(e)(1) of the Public Utility Regulatory Policies Act of 1978 is amended by inserting after "qualifying small power production facilities" the following: "or any investment or acquisition of any other interest therein".

○

97TH CONGRESS
1ST SESSION

S. 1966

To eliminate unnecessary paperwork and reporting requirements contained in the Public Utility Regulatory Policies Act of 1978.

IN THE SENATE OF THE UNITED STATES

DECEMBER 15 (legislative day, NOVEMBER 30), 1981

Mr. DANFORTH introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

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A BILL

To eliminate unnecessary paperwork and reporting requirements contained in the Public Utility Regulatory Policies Act of 1978.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That section 116 of the Public Utility Regulatory Policies Act of 1978 is repealed.

SEC. 2. The item relating to section 116 in the table of contents in section 1(b) of such Act is repealed.

SEC. 3. The repeals made by sections (1) and (2) shall take effect on the day after the day on which the Secretary of

Energy submits to the President and the Congress the report required to be submitted in 1982 under section 116(b) of the Public Utility Regulatory Policies Act of 1978.

○

STATEMENT OF HON. J. HUNTER CHILES III, DIRECTOR, OFFICE OF POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY

Mr. CHILES. Good morning, Mr. Chairman. I thank you for the opportunity to address the committee regarding S. 1885 and S. 1966.

Both bills amend the Public Utility Regulatory Policies Act of 1978, known as PURPA, or amend portions of the Federal Power Act which were themselves amended by PURPA.

To give you some perspective on where we are today, the PURPA legislation as originally proposed by the previous administration in 1977 provided for temporary Federal takeover of State retail ratemaking responsibilities if States did not reform their rate structures to the satisfaction of the Federal Government.

As actually enacted, PURPA sought to utilize the established mechanisms of State retail ratemaking bodies rather than to take over their responsibilities. PURPA imposed a number of primarily procedural and reporting requirements on utilities and State regulatory bodies. In title I, State regulatory bodies and nonregulated utilities were required to consider, but not necessarily adopt, a number of Federal standards regarding rate structures and other matters. Federal standards were enacted for establishing costs of serving customers; for time-of-day rates; for seasonal rates; for interruptible rates; for declining block rates; and for load management techniques.

Under section 116 of PURPA, State regulatory bodies and unregulated utilities are required to report annually to DOE on their progress in meeting the legal requirement to consider these Federal standards. Section 116 also requires DOE to report to Congress on the progress of these entities in meeting the title I statutory requirements.

One of the bills before us today, S. 1966, would repeal section 116 of PURPA. The repeal would take place automatically as soon as the 1982 Federal report is submitted.

Mr. Chairman, DOE supports the enactment of S. 1966. Most of the title I requirements have been met by most of the States as of the deadline of November 9, 1981. A few States have not met the title I requirements because they are awaiting the Supreme Courts' decision on the constitutionality of titles I and IV and section 210 of PURPA.

I believe there is no useful purpose in continuing to maintain staff on either the State or Federal levels for the purpose of submitting annual reports after 1982 when there will be little new or important information in such reports. I, therefore, wholeheartedly endorse the enactment of S. 1966.

Section 210 of title II of PURPA was enacted to promote certain electricity-producing technologies. Section 210 requires that utilities purchase the electrical output of "qualifying" cogeneration and small power production facilities, or QF's [for "qualifying facilities"], as defined in section 201 of PURPA. The purchases from QF's must be made at prices that are nondiscriminatory to the QF, are just and reasonable to the consumers of the electric utility, and are in the public interest, and are no higher than the costs that the utility avoids in making the purchase from the QF.

The Federal Energy Regulatory Commission [FERC] is required to prescribe rules for States to follow in establishing rates for QF's that meet these statutory criteria. The rules promulgated by FERC, pursuant to section 210, require that QF's be paid the full "avoided costs" that the utility would have incurred were it not for the purchase from the QF's, although FERC does allow utilities and QF's to negotiate prices at less than the full avoided cost level.

On January 22, 1982, the U.S. Court of Appeals for the District of Columbia ruled that the FERC had not adequately demonstrated that its full "avoided cost" rule met all the statutory requirements of section 210. The Court remanded the rulemaking back to FERC with a recommendation that FERC examine whether allowing QF's to receive a price for their output equal to a percentage of fuil avoided costs might better meet the statutory criteria. FERC has appealed the decision.

Section 201 of title II allows a cogenerator or small power producer to become a qualifying facility, and thus become eligible for section 210 benefits, if it is owned by a person "not primarily engaged in the generation or sale of electric power" [other than from the QF].

FERC has defined "not primarily owned" as not more than 50 percent. Thus, electric utilities cannot have a 50-percent equity share or more in a QF if the QF is to retain eligibility for section 210 benefits.

DOE supports section 210 of PURPA. Section 210 eliminates a number of regulatory barriers for certain energy technologies. It allows new sources of power that may be cheaper from existing ones to come onto the grid. Some of these sources can provide energy more quickly than conventional sources.

There are three issues that need to be addressed before we can endorse S. 1885. These are whether States are following FERC rules properly in setting rates for purchases of power from QF's; whether the prospect of a utility-owned QF selling power to itself at rates not subject to traditional rate regulation, introduces any economic distortions; and whether there are any issues involving potentially unfair competition if utilities are able to wholly own QF's eligible for section 210 benefits.

Regarding the first issue, DOE believes that most States have been setting rates for purchases of QF power which are consistent with FERCs section 210 rules for such rate setting.

I am concerned, however, that a few States have established rates that are higher than allowed by FERC's rules. The effect of such high rates is, in essence, to subsidize the QF, raise consumer rates, and cause less economical generating sources to displace more economical sources.

In some cases, we see the potential for relatively less economical oil or natural gas cogeneration electrical generating sources to replace more economical sources powered with abundant domestic resources, such as coal-fired central station plants. Congress very explicitly did not intend these results. It is DOE's hope that FERC, in its rules implementing Section 210 of PURPA, will be able to give more specific guidance to the States in order to minimize this subsidization problem.

The second problem is one which I will refer to as "self dealing". This problem already exists today for utilities which own 50 percent or smaller share in QF's; but since there are an insignificant number of such facilities, the problem is minimal at present. However, under 100 percent utility ownership of QF's, we would expect the problem to grow in size.

The "self dealing" problem can be illustrated with an example. I have in mind a situation where a utility burning oil or natural gas at the margin 24 hours a day establishes a number of profitable wholly owned QF's; for example, some small hydro and some coal-fired cogeneration.

High "avoided cost" rates are based in large part upon the high costs of oil fuels, and prospectively, natural gas as its price rises under the NGPA.

What incentive would such a utility have to try to reduce consumer bills by building plants that would reduce oil and gas use where the effect of doing so would be to reduce avoided energy costs paid to other QF's and thereby the profitability of their QF's? The answer may be none.

This is especially true under the financial conditions facing most utilities today. In many States, utility investments in new construction in effect penalize shareholders because of underrecovery of the capital costs of such investments. The "self-dealing" problem may be minimized if the rate paid to QF's is based upon correctly calculated long-term avoided costs and if Federal and State regulators of utilities are conscientious in insuring that utilities pursue construction programs that offer the best prospects of minimizing costs in the long term.

I believe that the "self-dealing" problem, if properly dealt with by regulators, is not a sufficient basis to deny utilities the benefits of section 210 that are available to other corporations. Rather, I believe that FERC and State regulators have the responsibility of reviewing utility long-term capacity expansion plans to see that utility profit maximizing—a positive goal—does not inhibit achievement of the goal of optimizing the utility's economic efficiency.

Third, the issue of competition is also germane to S. 1885. One aspect of that issue has been underscored by the January 22 court of appeals decision referred to above. If that decision is upheld, a utility, by refusing to interconnect with a QF, may force the QF to seek an interconnection order from FERC under sections 210 and 212 of the Federal Power Act.

Such an order must be based upon a number of substantial findings by FERC. Obtaining such an order might present a formidable regulatory barrier to QF's in this position.

However, if a utility owned a QF, there would obviously be no interconnection problem. A utility, by refusing to interconnect nonutility owned QF's, while readily interconnecting its own QF's, could create a significant competitive disadvantage for nonutility QF's. To the extent that a simple interconnection obligation on utilities exists, as it does in the current FERC rule, the chances of a utility's abusing its position in this regard would appear minimal. However, if the court of appeals decision which vacates the

FERC rule is upheld, it would create a problem which Congress should address promptly and directly.

Mr. Chairman, I have spoken of some of the potential problems that currently exist under section 210 or that might exist under 100 percent utility ownership of QF's. Let me now speak of some of the benefits of 100 percent utility ownership of QF's.

A 100 percent utility ownership will, in my mind, undoubtedly cause more QF electrical generation to occur. If avoided cost rates are properly set, and if capacity expansion plans are rational, this will be positive.

I mentioned earlier our belief that oil- and gas-fired cogeneration is likely to be economical in few cases if avoided costs are correctly calculated.

On the other hand, I believe that coal-fired cogeneration or generation with wood waste, to give two examples, are likely to be very economical, and I think that the expertise that utilities can bring to bear will be very helpful in bringing more economic capacity on line.

Second, it makes no sense to me from an equity viewpoint to penalize electric utilities by preventing them from entering a field where oil companies, steel companies, and consortiums of investors can enter. If section 210 of PURPA has the potential for contributing positively to our national energy posture, what sense does it make to exclude the industry that knows the most about electrical generation?

Third, allowing 100 percent utility ownership of QF's may in fact bring the benefits of enhanced competition to the field. I for one, would argue that a utility may well be able to build and operate a QF at a lower price than a group that doesn't have expertise building and operating electrical generating plants.

Mr. Chairman, of the three potential problems mentioned above, one of them—the problem of self-dealing—is ongoing and should be left to State and Federal regulators.

The other two—avoided cost rates set above economically rational levels and the potential anticompetitive aspects presented by existing interconnection statutory provisions—are amenable to more direct solution at the Federal level.

DOE believes that S. 1885 should be enacted if these two remaining problems can be addressed within it. Regarding State regulators setting rates higher than economically rational—or indeed higher than authorized by Congress—some clear statement of congressional intent, perhaps in the statement of managers accompanying S. 1885, might greatly assist in this regard.

Mr. Chairman, I would like to make a final comment on section 210. Some observers feel that section 210 deregulates electricity produced by QF's. While section 210 does release QF's from many Federal and State regulatory provisions, it does not achieve total deregulation. The pricing provisions of section 210 instead establish a two-tiered, regulatory structure—one pricing structure for QF's and one for all other electric generating technologies.

This two-tiered structure, by offering greater incentive to some, generating sources to others, could conceivably cause a somewhat less economic generator to be chosen, even after correcting the problems mentioned above.

Some economic theorists have proposed that PURPA 210 benefits be extended to all generating sources, not just QF's. Their argument is that if all generating forms were so eligible, then the cheapest source would be more likely to be built, because all generators would be eligible for the same rates. DOE has no current position on this proposal.

However, as part of the ongoing electricity policy project (EPP), DOE will be examining the issue of deregulation generally, amongst many other proposed changes in the structure of the electric utility industry. Such changes range from very small incremental changes through "partial deregulation" changes, such as the proposal to open section 210 to all generating types, to more comprehensive deregulation proposals.

The purpose of the electricity policy project is to comprehensively examine the problems of the industry, the potential implications for the Nation of these problems, and the range of potential solutions to the problems. We hope to have preliminary results on the EPP by late summer.

Mr. Chairman, this concludes my testimony. I will be happy to respond to your questions.

[The prepared statement of Mr. Chiles follows:]

STATEMENT OF HON. J. HUNTER CHILES III, DIRECTOR, OFFICE OF POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY

Mr. Chairman, thank you for the opportunity to address the Committee regarding S.1885 and S.1966.

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There are three issues that need to be addressed in considering S.1885. These are:

1. Whether states are following FERC rules properly in setting rates for purchases of power from QFs;

2. Whether the prospect of a utility-owned QF selling power to itself at rates not subject to traditional rate regulation, introduces any economic distortions; and

3. Whether there are any issues involving potentially unfair competition if utilities are able to wholly own QFs eligible for section 210 benefits.

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Mr. Chairman, I have spoken of some of the potential problems that currently exist under section 210 or that might exist under 100% utility ownership of QFs. Let me now speak of some of the benefits of 100% utility ownership of QFs.

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Mr. Chairman, of the three potential problems mentioned above, one of them - the problem of self dealing - is ongoing and should be left to state and federal regulators. The other two - avoided cost rates set above economically rational levels and the potential anti-competitive aspects presented by existing interconnection statutory provisions - are amenable to more direct solution at the Federal level. DOE believes that S.1885 should be enacted if these two remaining problems can be promptly addressed. Regarding state regulators setting rates higher than economically rational (or indeed higher than authorized by Congress), some clear statement of Congressional intent, perhaps in the Statement of Managers accompanying S.1885, might greatly assist in this regard.

Mr. Chairman, I would like to make a final comment on Section 210. Some observers feel that Section 210 "deregulates" electricity produced by QFs. While Section 210 does release QFs from many federal and state regulatory provisions, it does not achieve total deregulation. The pricing provisions of Section 210 instead establish a two-tiered, regulatory structure - one pricing structure for QFs and one for all other electric generating technologies. This two-tiered structure, by offering greater incentive to some generating sources than others, could conceivably cause a somewhat less economic generator to be chosen, even after correcting the problems mentioned above. Some economic theorists have proposed that PURPA 210 benefits be extended to all generating sources, not just QFs. Their argument is that if all generating forms were so eligible, then the cheapest source would be more likely to be built, because all generators would be eligible for the same rates. DOE has no current position on this proposal. However, as part of the ongoing Electricity Policy Project (EPP), DOE will be examining the issue of deregulation generally, amongst many other proposed changes in the structure of the electric utility industry. Such changes range from very small incremental changes thru "partial deregulation" changes, such as the proposal to open Section 210 to all generating types, to more comprehensive deregulation proposals. The purpose of the Electricity Policy Project is to comprehensively examine the problems of the industry, the potential implications for the nation of these problems, and the range of potential solutions to the problems. We hope to have preliminary results on the EPP by late summer.

Mr. Chairman, this concludes my testimony. I will be happy to respond to your questions.

Senator HUMPHREY. Thank you, Mr. Chiles. Mr. Chiles, does the administration believe that the statutory ownership limitation of PURPA applies to wholly owned subsidiaries or to utilities?

In other words, is it the administration's opinion that in order to allow a utility or its wholly owned subsidiary to obtain the benefits of section 210, Congress must amend PURPA?

Mr. CHILES. It's a legal issue and I'm not a lawyer, so I can't really answer this fully. But I asked our lawyers to look at this. The initial reading is the answer to that question is yes.

Senator HUMPHREY. You are saying yes, Congress must amend PURPA in order for utilities or their wholly owned subsidiaries to obtain these benefits?

Mr. CHILES. Yes. That is the initial reading we have.

Senator HUMPHREY. On page 4 of your testimony you list three issues that you feel need to be addressed before the administration can endorse S. 1885. Does the administration have these under study?

Mr. CHILES. We have them under study, but I should also point out that on the first of those issues we think that the State and FERC are the ones that should make sure the rules are applied correctly. On the other two issues, the interconnection issue that I mentioned and what I call self dealing, we feel very strongly they should be addressed within this bill.

Senator HUMPHREY. But you do have studies underway; is that correct?

Mr. CHILES. We have quite a study underway that will be finished, hopefully, sometime in October that will address this and almost any other issue you can think of on electric utilities. I don't think you need those studies to make these decisions.

Senator HUMPHREY. On page 5 of your testimony you state that self dealing may be a problem. Why do you feel that State public utility commissions cannot address this problem themselves?

Mr. CHILES. I think to some degree they can. Although the process that is set up in the FERC opinion is upheld in the court of appeals. It puts the qualifying facility owner in the position of having to go through a FERC hearing to get it. The hassle and the time involved may just be too much. They may say it's not worth it.

Senator HUMPHREY. What about the self-dealing problem on page 6? You think that can be done at the State level, or must FERC deal with it?

Mr. CHILES. I think the States can deal with it very effectively. However, I do think it should be written into the law that the utility does not have this option of dragging its feet on the interconnection. The main thrust of this law is to try to get these qualifying utilities on line, and I don't think you should have things that allow a utility to drag its feet in these matters.

Senator HUMPHREY. Would you be able to provide the committee with recommended appropriate language to address these two points?

Mr. CHILES. Yes, sir. We would be glad to do that.

[The information follows:]

Department of Energy
Washington, D.C. 20585

MAY 6 1982

Ms. Marilyn Burkhardt
Counsel
Committee on Energy and
  Natural Resources
United States Senate
Washington, D.C. 20510

Dear Ms. Burkhardt:

While testifying on S. 1855 on April 19, 1982, J. Hunter Chiles, III agreed to furnish the subcommittee with recommended appropriate language to amend section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

The attached draft language is forwarded in response to that request. This language is provided as a drafting service only, and does not represent the views of the Department of Energy.

Sincerely,

Robert G. Rabben
Assistant General Counsel
for Legislation

Attachment

APPENDIX A

Suggested Statement of Congressional Intent as to Implementation of Section 210(b) of PURPA by State Regulatory Authorities

It has come to the attention of [the Managers] that, in certain instances of State regulatory authority implementation of Section 210(b) of PURPA, rates for purchases of power by utilities from qualifying cogeneration or small power production facilities (QFs), purportedly set at the full avoided cost level under the authority of the Federal Energy Regulatory Commission's rules implementing Section 210(b), are in fact being set at levels higher than the full avoided costs, appropriately determined, of the utilities concerned. It is apparent that, because the utility's avoided costs are not being correctly calculated, rates which subsidize QFs are being set in these jurisdictions. While the Congress recognizes, and does not wish to preempt the authority of the States to set rates above the full avoided cost level on the basis of State law, it is not the intention of Congress that PURPA should be used as authority to effect subsidies of QFs at the expense of electric utilities or of consumers of electric energy. Accordingly, State regulatory authorities that set rates for purchases of QF power on the authority of Section 210(b) of PURPA should, in order to comply with the Commission's rules, set rates on the basis of methodologies that accurately calculate utilities' long-run avoided costs (such as the differential revenue requirements method) and such calculations should be based upon utility capacity expansion plans that are designed to minimize system and consumer costs over time. The Commission should, in its oversight of State regulatory authority implementation of Section 210, take appropriate steps to ensure that State authorities base rates upon these principles if they are to conform the standards contained in Section 210(b).

APPENDIX B

Proposed Additions to S. 1885 to Amend Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) to Ensure that Cogeneration and Small Power Production Facilities which Qualify for Sales to or Purchases from Utilities Under Section 210 of PURPA May Interconnect with Utilities Without the Need to Obtain an Interconnection Order From the FERC Under Sections 210 and 212 of the Federal Power Act

Add after section 2, the following new section --

"SEC. 3. COGENERATION AND SMALL POWER PRODUCTION -- Section 210(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3(a)) is amended --

"(1) in paragraph (1), by striking "and" after "small power production facilities" and inserting a comma;

"(2) in paragraph (2), by striking the period after "such facilities" and inserting ",and"; and

"(3) by adding a new paragraph (3) as follows --

> (3) interconnect with such a facility insofar as necessary to effect sales to or purchases from such a facility under this section."

Add after section 3, either of the following alternative subsections --

"SEC. 4. EXEMPTIONS -- Section 210(e) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. §824a-3(e)) is amended --

"(1) in paragraph 3(B), by striking "210", and ",or 212"; and

"(2) by adding a new paragraph (4) as follows --

> (4) Sections 210 and 212 of the Federal Power Act do not apply to qualifying small power production facilities or qualifying cogeneration facilities in the exercise of their rights under section 210(a) of this Act to interconnect in order to sell electric energy to or purchase electric power from these facilities."

Alternative

"(1) by striking paragraph 3(B) and redesignating paragraph 3(C) as paragraph 3(B); and

"(2) by adding a new paragraph (4) as follows --

> (4) Sections 210 and 212 of the Federal Power Act do not apply to qualifying small power production facilities or qualifying cogeneration facilities in the exercise of their rights under section 210(a) of this Act to interconnect in order to sell electric energy to or purchase electric power from these facilities."

RATIONALE

Section 3: Section 210(a)(3) of PURPA is intended to clarify the Commission's authority to order interconnection under section 210 of PURPA. Section 210(a)(3) imposes upon electric utilities the unqualified obligation, implicit in existing law, to interconnect with qualifying cogeneration and small power production facilities whenever necessary to make effective sales to or purchases from those facilities under section 210(a)(1) and (2). In order to interconnect, qualifying facilities would not be required to obtain an interconnection order from the Commission under section 210 of the Federal Power Act to make these sales or purchases effective, and the substantive and procedural provisions of sections 210 and 212 of the Federal Power Act would not apply. This amendment makes clear that the Commission's original rule contained in 18 C.F.R. §292.303(c), which imposed the obligation to interconnect upon utilities, is consistent with section 210 of PURPA. It is not the intent of the Congress that the Commission should require an evidentiary hearing as a prerequisite for interconnection under section 210 of PURPA. Section 210(a)(3) is not intended however to detract from the right of qualifying facilities to apply for an interconnection order under sections 210 and 212 of the Federal Power Act or from the benefits and protections sections 210 and 212 may confer upon qualifying facilities.

Section 4: Section 4 conforms the exemption provisions of section 210 of PURPA to the new section 210(a)(3), which imposes upon electric utilities the unqualified obligation to interconnect with qualifying small power production and cogeneration facilities to effect sales to or purchases from these facilities under section 210 of PURPA. Section 4 makes clear that these facilities are exempt, for the purposes of exercising their rights under section 210 of PURPA, from the obligation to obtain an interconnection order from the Federal Energy Regulatory Commission under sections 210 and 212 of the Federal Power Act.

Further Rationale if Alternative Paragraph (1) of Section 4 is Adopted:

The exclusion of section 211 of the Federal Power Act from the Commission's authority to exempt qualifying facilities from the Federal Power Act under section 210(e) of PURPA is meaningless because qualifying facilities are not included in the class of potential applicants for a wheeling order from the Commission under section 211 of the Federal Power Act.

Senator HUMPHREY. Thank you very much, Mr. Chiles, for your testimony.

Our next witness is the Honorable C. M. "Mike" Butler, Chairman of the Federal Energy Regulatory Commission.

STATEMENT OF HON. C. M. BUTLER, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION; ACCOMPANIED BY CHARLES MOORE, GENERAL COUNSEL, AND ROBERT MEANS, DIRECTOR, OFFICE REGULATORY ANALYSIS

Mr. BUTLER. Good morning, Mr. Chairman.

Senator HUMPHREY. Do you want to introduce your staff?

Mr. BUTLER. I have on my right Mr. Charles Moore who is our general counsel. On my left is Robert Means, who is the director of office regulatory analysis.

What I would like to do this morning, if you would like for me to proceed, would be simply to say a few words about my testimony. The only thing that I would like to read from it would probably be, for the benefit of those in the audience, the point from about page 8 toward the rear.

I would also like to point out for the benefit of the reporter a couple of corrections that ought to be made in this. Those are on page 6, at the top of the page in the first line, the word "rate" should be changed to the word "sale". On page 10, at the bottom of the page, there is a dropped line. I apologize for that. The last line, or the last sentence should read, "The implication utility owned or utility affiliated qualifying facilities must be even more a matter of speculation."

Now, with respect to the introductory part of the testimony, what we've done is simply to consider, first of all, if there are legal questions involved in whether electric utilities are now properly precluded from the benefits of PURPA by existing FERC rules.

The second thing we do is raise some relevant policy questions.

As to the first matter, I disagree, quite frankly, with the position of Mr. Chiles' legal advisers. It is my opinion that the current statutory language of PURPA clearly does permit companies affiliated with public utilities to own 100 percent of a qualifying facility.

I also feel that the language rather clearly excludes a utility itself from owning 100 percent of a qualifying facility. To that extent, if you wanted to get to the point where utilities were able to own 100 percent of the qualifying facility directly, I believe a statutory amendment would be required.

Now, in connection with the legal question, the Commission, in its order 70, made a decision to exclude utilities from either directly or indirectly (that is through an affiliate) owning 100 percent of a qualifying facility. The rationale for that I cannot find, quite frankly, in order 70.

So, in looking at this question we decided to start from scratch. With respect to policy questions, we came to essentially the same conclusions that the Department of Energy did, although I don't think from what we have seen of those policy questions at this point that they are terribly serious. It may be that further analysis through the process of a rulemaking proceeding at the Commission for example, might elicit information indicating that they are more serious than they now appear to be.

What I would like to do with respect to those policy questions is to start in the middle of page 8 and read what you will find in my prepared testimony:

At the same time, however, the extension of section 210 benefits to utility affiliated facilities does raise some questions. They are of three general kinds. The first is an argument about cream-skimming. The argument holds that a utility having a number of opportunities for congeneration or small power production might undertake the more costly ones itself, seeking recovery of their costs through conventional rate proceedings, while leaving the less costly ones to be exploited by subsidiaries that could sell the power to the utility at avoided cost. This argument seems to me to be of limited practical importance, however. It rests on the implicit premise that utilities would directly undertake significant investments in cogeneration under conventional rate regulation. This premise is not supported by experience. Even during the 1950's and 1960's, when utilities were generally earning adequate returns on their investments, their investment in cogeneration was negligible. I see no reason to believe that utilities would undertake substantial cogeneration investments under conventional rate regulation today, when they are generally unable to earn even their cost of capital.

At this point I would note that there are some papers that have been written by DOE that indicate the elcctric utility industry is becoming generally risk adverse. The rationale for that is they are not earning their cost of money.

The second potential problem is distortion of utility investment decisions. At least in theory, the extension of the benefits of section 210 to utility affiliated facilities could skew investment decisions in two ways. First, even if the utility were earning an adequate rate of return through conventional rate proceedings, cogeneration or small power production might offer a still better one. A situation in which certain kinds of generating technology offer a better return simply as a result of regulation could lead to inefficient allocations of capital.

Second, if utility-owned facilities qualify for section 210 benefits, the utility's return on its investment in such facilities will depend immediately on the price at which it buys the cogenerated electricity and ultimately on the utility's avoided cost. Again in theory, this link between the return on the utility's investment and the utility's avoided cost could create perverse incentives, since direct utility investment that lowered its avoided cost would also lower its return on its investment in its subsidiary." This is the self dealing problem as to which Mr. Chiles testified a few moments ago. "This argument also seems to me to have only limited practical importance. Technological and economic factors limit the opportunities for cogeneration and small power production, and this is as true for utility-affiliated facilities as it is for independent ones. There seems to me to be little realistic possibility that utilities could substitute affiliated cogeneration on small power facilities for significant amounts of their conventional generating capacity.

That's not to say that this kind of a problem couldn't arise in somewhat more aggravated fashion with respect to an individual utility, but on an industry-wide basis one would not expect this to be a major problem. At least I wouldn't.

The third potential problem is discrimination against independent cogenerators and small power producers. Concerns have been expressed that utilities would preempt cogenerating and small power production opportunities for themselves or that they would favor their own qualifying facilities over independently owned ones in the dispatch of electricity. This potential problem is more difficult to assess, and it is unclear that current statutory prescriptions and available enforcement tools are inadequate to prevent the forecasted evil.

The reality and extent of these potential problems, and the proper regulatory response to them, are unclear at this point. Although PURPA is now nearly 3½ years old, the first generation of contracts between utilities and qualifying facilities are still being negotiated. The implications of utility-owned or utility-affiliated qualifying facilities must be even more a matter of speculation.

In closing, I would like to state that I do not believe that this uncertainty is adequate grounds for inaction. However, uncertainty makes it appropriate to proceed with some caution. I therefore have directed staff to conduct a study of both the emerging contractual relationships between electric utilities and qualifying facilities and the issues that would be posed by allowing utility-affiliated facilities to qualify for the benefits of section 210. It is my hope that at an early point this study can be converted into a rulemaking proceeding that can deal concretely with these issues.

Without reading the last paragraph, I only note that it points out that S. 1966 dealing with section 116 of PURPA is essentially the responsibility of DOE. Since the Commission does not have direct responsibility for it, we chose simply to defer to the position that was taken by the Department of Energy.

That concludes my prepared remarks, Mr. Chairman. I'll be happy to try to answer any questions that I can.

[The prepared statement of Mr. Butler follows:]

STATEMENT OF
C. M. BUTLER III
CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION
BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

April 19, 1982

I am pleased to appear before you today to discuss some of the legal and policy issues raised by the proposed extension of the benefits of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) to utility-owned cogeneration and small power production facilities.

I would like to begin by trying to define the basic issue involved in the proposed extension. Electric utilities are presently permitted to invest in cogeneration and small power production subject to the usual regulatory standard of prudence. The issue is: should utility-owned cogeneration and small power production facilities be permitted to receive the benefits available under section 210 of PURPA to owners of "qualifying cogeneration facilities?" From the standpoint of electric utilities, the most significant of these benefits would seem to be the right to sell electricity at a price that is, under current FERC regulations, equal to 100 percent of the the cost that the utility avoids by not generating the power itself or purchasing incremental power supplies from another generation source. 1/

Although there is no explicit statutory preclusion, FERC regulations deny the benefits of PURPA section 210 where utilities directly or indirectly own more than 50 percent of the facility. 2/ At the time that this regulation was issued, the Commission apparently took the view that it was implicitly required by PURPA. 3/ S. 1885 would amend PURPA to make it

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1/ Section 210 of PURPA and the Commission's implementing rules confer four benefits on qualifying facilities. Section 210(a) of PURPA and section 292.303 of the Commission's rules require utilities to buy electricity from, and sell electricity to, qualifying facilities. Section 210(b) of PURPA requires the rates for such utility purchases to satisfy specified criteria. Section 292.304 of the Commission's rules implements this section by requiring fully avoided cost pricing of electricity from newly developed qualifying facilities, absent a negotiated agreement or a waiver request from the state regulatory authority. Section 210(c) of PURPA and section 292.305 of the rules provide for just and reasonable and nondiscriminatory electric service from utilities to qualifying facilities. Section 210(e) of PURPA and sections 292.601 and 292.602 of the rules provide for exemptions from certain electric utility regulations. The exemption from parts of the Federal Power Act and similar state laws, coupled with the avoided cost pricing, would provide the greatest benefit to utility and industry subsidiary and facilities. Exemption from the Public Utility Holding Company Act is also viewed as advantageous.

2/ 18 C.F.R. §§ 292.203 and 292.206(b) (1981).

3/ See Order No. 70, Small Power Production and Generating Facilities -- Qualifying Status, Docket No. RM79-54 (issued March 20, 1980). I say "apparently" because the Commission provided virtually no rationale for denying "qualification" under §292.203 of its rules to companies affiliated with, and thus controlled by, public utilities. See 45 Fed. Reg. 17959, 17970 (March 20, 1980).

clear that the Commission could extend the benefits of section 210 to utility-owned cogeneration facilities.

The question of utility qualification for section 210 benefits presents two specific sub-issues. First, could the FERC lawfully allow broader utility participation in such facilities under the existing statute? Second, would it be sound policy to allow such broader participation?

The legal question is, in my view, an easy one to answer. PURPA section 210 confers its benefit on "qualifying cogeneration facilities" and "qualifying small power production facilities." There are some differences in the treatment of the two kinds of facilities, 4/ but in discussions of the statute they are

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4/ The differences concern the exemptions from utility-type regulation. All qualifying cogeneration facilities are fully exempt. Qualifying small power production facilities of greater than 30 megawatts are not granted any exemptions unless the primary energy source of the facility is biomass or geothermal energy. Biomass-fired qualifying small power production facilities of greater than 30 megawatts are exempt from the Public Utility Holding Company Act and state utility laws and regulations but not the Federal Power Act. Geothermal qualifying small power production facilities of all sizes are granted all exemptions. All utility-owned geothermal small power production facilities are exempt from the Public Utility Holding Company Act. Under section 643 of the Energy Security Act of 1980, the Commission has the authority to exempt utility-owned geothermal small power production facilities from the Federal Power Act and state regulation. The Commission has not yet acted on this authority, however.

often referred to together as "qualifying facilities," and I will sometimes use that term here to refer to both.

One element in the statutory definition of qualifying facility is that it be "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." 5/ The legal controversy over utility participation turns on the meaning of this language. In this connection, the statutory definition of the term "person" includes corporations, but not affiliated companies. 6/ Rather clearly the statute means that a cogeneration or small power production facility owned solely and directly by an electric utility cannot be a qualifying facility. Two legal questions, however, are not so clearly resolved by the language. First, can an electric utility have a direct partial ownership interest in a qualifying facility? Second, can such a facility be wholly owned by an electric utility's corporate affiliate?

In its cogeneration regulations, the Commission answered the first question in the affirmative, allowing cogeneration and small power production facilities to qualify for section 210 benefits if an electric utility had as much as a 50 percent

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5/ 16 U.S.C. §§ 796(17)(C)(ii), 796(18)(B)(ii) (Supp. 1978).

6/ 16 U.S.C. §§ 796(4) (1976).

ownership interest in the facility. 7/ I am in full agreement with the Commission's treatment of this first question as a matter of statutory interpretation.

The second question, however, the Commission answered in the negative. Section 292.206 of the Commission's regulations subjects ownership by a utility subsidiary or a public utility holding company to the same 50 percent limit. The Commission conceded that this result was not required by a literal reading of the statute, but took the position without further reason that "the thrust of section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned primarily by electric utilities or their subsidiaries." 8/

I disagree with the legal interpretation of PURPA embodied in section 292.206(b). The literal terms of the statute certainly provide no support for the conclusion that companies affiliated with utilities cannot qualify for the benefits of section 210 of PURPA. The statute limits those benefits to qualifying facilities "owned by a person not primarily engaged

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7/ 18 C.F.R. § 292.206(b)(1981).

8/ Supra note 3, at 2.

in the generation or sale of electric power. . . ." 9/ The term "person" is defined, for purposes of this provision, to include a corporation, but does not include affiliated companies. 10/ There is nothing ambiguous about the terms used in the statute, and, under familiar canons of statutory construction, there is thus no justification for going behind their plain meaning. Even if one were to refer to the legislative history of PURPA, however, one searches in vain for an articulated basis for extending the statutory preclusion to companies affiliated with utilities.

Broader utility participation in cogeneration and small power production appears to offer significant benefits. Technological and economic factors limit the contribution that can be made by cogeneration and small power production, whether independently-owned or affiliated with electric utilities. The extension of the benefits of section 210 to utility-affiliated facilities, therefore, is in no way a substitute for measures that would deal with the fundamental financial problems of the electric utility industry. Such an extension does appear, however, to be a way of increasing the Nation's supply of

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9/ *Supra* note 5, at 4.

10/ 16 U.S.C. §§ 796(3) and 796(4) (1976).

electricity without either aggravating utilities' financial difficulties on one hand or imposing additional burdens on utility ratepayers on the other.

Qualifying status for utility-affiliated facilities could conceivably enable financially troubled utilities to expand their effective generating capacity by allowing them to earn an attractive return on investment in cogeneration and small power production. The opportunity for such a return might be necessary for full utility exploitation of the possibilities of cogeneration and small power production even if utilities were currently earning a return that was adequate by conventional regulatory standards. The reason is that these sources of power may involve technological and business risks significantly greater than those encountered in conventional power generation. Under current conditions, with utilities' earned rates of return lagging behind their allowed rates of return and their cash income well below historical levels, the basic argument for allowing an attractive return on such investments is reasonably compelling.

Such utility investments should not impose an additional burden on ratepayers even if they qualify for the benefits of section 210. The maximum price that utilities can be required to pay for power from a qualifying facility is the cost that the utility avoids through not having to generate the power itself, and it is unlikely that a utility would be allowed to pay a price in excess of its avoided cost for power produced by one of its own affiliates. If avoided cost is properly determined, utility ratepayers are never worse off by reason of a utility's purchase of power from a qualifying facility, and they are better off if the price is set anywhere below avoided cost. The logic of this argument is not altered if the qualifying facility is owned by a company affiliated with the utility.

At the same time, however, the extension of section 210 benefits to utility-affiliated facilities does raise some questions. They are of three general kinds. The first is an argument about cream-skimming. The argument holds that a utility having a number of opportunities for cogeneration or small power production might undertake the more costly ones itself, seeking recovery of their costs through conventional rate proceedings, while leaving the less costly ones to be exploited by subsidiaries that could sell the power to the utility at avoided cost. This argument seems to me to be of limited practical importance, however. It rests on the implicit premise that utilities would directly undertake significant investments in cogeneration under conventional rate regulation. This premise is not supported by experience. Even during the 1950's and 1960's, when utilities were generally earning adequate returns on their investments, their investment in cogeneration was negligible. I see no reason to believe that utilities would undertake substantial cogeneration investments under conventional rate regulation today, when they are generally unable to earn even their cost of capital.

The second potential problem is distortion of utility investment decisions. At least in theory, the extension of the benefits of section 210 to utility-affiliated facilities could skew investment decisions in two ways. First, even if the utility were earning an adequate rate of return through conventional rate proceedings, cogeneration or small power production might offer a still better one. A situation in which certain kinds of generating technology offer a better return simply as a result of regulation could lead to inefficient allocations of capital. Second, if utility-owned facilities qualify for section 210 benefits, the utility's return on its investment in such facilities will depend immediately on the price at which it buys the cogenerated electricity and ultimately on the utility's avoided cost. Again in theory, this link between the return on the utility's investment and the utility's avoided cost could create perverse incentives, since direct utility investment that lowered its avoided cost would also lower its return on its investment in its subsidiary.

This argument also seems to me to have only limited practical importance. Technological and economic factors limit the opportunities for cogeneration and small power production, and this is as true for utility-affiliated facilities as it is for independent ones. There seems to me to be little realistic possibility that utilities could substitute affiliated cogeneration on small power facilities for significant amounts of their conventional generating capacity.

The third potential problem is discrimination against independent cogenerators and small power producers. Concerns have been expressed that utilities would preempt cogenerating and small power production opportunities for themselves or that they would favor their own qualifying facilities over independently-owned ones in the dispatch of electricity. This potential problem is more difficult to assess, and it is unclear that current statutory prescriptions and available enforcement tools are inadequate to prevent the forecasted evil.

The reality and extent of these potential problems, and the proper regulatory response to them, are unclear at this point. Although PURPA is now nearly three and a half years old, the first generation of contracts between utilities and qualifying facilities are still being negotiated. The implications of utility-owned or utility-affiliated qualifying facilities must be even more a matter of speculation.

In closing, I would like to state that I do not believe that this uncertainty is adequate grounds for inaction. However, uncertainty makes it appropriate to proceed with some caution. I therefore have directed staff to conduct a study of both the emerging contractual relationships between electric utilities and qualifying facilities and the issues that would be posed by allowing utility-affiliated facilities to qualify for the benefits of section 210. It is my hope that at an early point this study can be converted into a rulemaking proceeding that can deal concretely with these issues.

If I could add a brief note to my testimony today, I would mention that when your Committee asked me to testify I was asked to comment on S. 1966 which would repeal section 116 of PURPA. That statutory provision requires each state regulatory authority and each nonregulated electric utility to report annually to the Secretary of Energy its consideration of the Federal standards regarding cost of service, declining block rates, time-of-day rates, seasonal and interruptible rates, and load management techniques. The implementation of this provision is the responsibility of the Secretary of Energy. Since the FERC is not involved with this requirement, I believe that we should defer to the position of DOE on this issue.

Senator HUMPHREY. Thank you, Mr. Butler. You disagree with Mr. Chiles with respect to ownership by utility holding companies, is that correct?

Mr. BUTLER. That is correct. By companies that are affiliated with public utilities.

Senator HUMPHREY. Are you suggesting then that FERC has exceeded its authority in Orders 69 and 70?

Mr. BUTLER. I think that is an arguable point. It is not crystal clear to me that FERC does not have the discretion to have reached the choice that it did. I believe that the choice that it made would be reversed in court, quite frankly, because the Commission did not articulate the rationale for the decision that they reached.

Had they gone through the kinds of policy considerations that were alluded to by Mr. Chiles and me in our testimony and reached the conclusion that utilities should not be able, either directly or indirectly, to own 100 percent of a qualifying facility, I think a different question would be presented and I'm not sure I know the answer to that question.

The question would have been whether or not FERC had the discretion to reach the result that it did.

Senator HUMPHREY. Does the Commission plan to institute a new rulemaking to permit companies affiliated with utilities to qualify for the benefits under section 210?

Mr. BUTLER. I should make it clear that my testimony is on behalf of myself. As is very frequently the case, these issues have not been taken directly to the Commission, so I can only speak for myself.

In that connection, as I mentioned at the tail end of the testimony, I am quite willing to recommend to the Commission that we go forward with an NOPR to consider changing our rule.

Senator HUMPHREY. Suppose your opinion prevails in the Commission and you were challenged in court, how long would it take to get a final resolution?

Mr. BUTLER. A year and a half is probably not unlikely.

Senator HUMPHREY. Wouldn't it be preferable for Congress to change the statute to remove any doubt?

Mr. BUTLER. I would think that would be very helpful. If Congress reaches a conclusion that these policy concerns are not substantial, I think it would be an appropriate choice for Congress to go forward with the legislation.

As a matter of fact, what I might suggest is that Congress should make it clear in S. 1885 that the FERC does not have the discretion to disallow it, or preclude utilities or affiliated companies from owning 100 percent of a qualifying facility. Effectively what you would be doing, Mr. Chairman, is reaching the decision yourself as a legislature with respect to the evils that we suggest may be there.

Senator HUMPHREY. Do you feel that utility participation in the benefits of PURPA would affect small power producers differently than it would affect cogenerators?

Mr. BUTLER. I am not sure that I do. I only say that because, quite frankly, I hadn't thought of that question. It has not occurred to me.

I would be glad to spend some time and provide you with an answer for the record.

Senator HUMPHREY. That would be helpful, yes.

How does the Commission plan to respond to the *American Electric Power Service Corp.* case?

Mr. BUTLER. The Commission has already responded by deciding to file a motion for rehearing in the District of Columbia Court of Appeals. That was not my choice, by the way. I simply lost the vote on that one. The reason for it is, my judgment is on the law Judge Wilkie was right. He did not say that the Commission could not establish a full avoided cost rule. He simply said that we didn't consider everything that we should have considered, and he did not, in my view, say that we could not establish an interconnect rule that would work expeditiously. I think the Commission should have brought the case back, taken a look at it on an expedited basis and try to come to some kind of resolution to those problems without spending more time in courts.

Senator HUMPHREY. That petition was denied, as you know. Where does the Commission plan to go now?

Mr. BUTLER. We will have to take another vote.

Charlie, do we have to take another vote on filing a petition?

Mr. MOORE. Yes.

Mr. BUTLER. The next step in the procedure would be a closed meeting in which the Commission will consider whether or not to go forward with the petition for certiorari. I don't argue against that, by the way. I would like to get the matter back into the Commission and try to get to a resolution. I think we could issue a bulletproof order, quite frankly.

Senator HUMPHREY. How long would it take the Commission to promulgate a new rule on avoided cost that is consistent with the decision as it now stands?

Mr. BUTLER. It would probably take 4 to 5 months, and I compare that with the 1½ years that I would expect this matter to be in litigation.

Senator HUMPHREY. How does the Commission intend to address the interconnect?

Mr. BUTLER. We can't do that until we get the record back. We don't have jurisdiction of the record since it is still in court. The hard question with respect to interconnection is whether or not you have to have a full-blown evidentiary hearing. They are time consuming and expensive.

Two things that occur to me are that the Commission might be able to deal with those issues, depending on what kind of a standard it could establish, possibly using the statutory hearing procedure.

Alternatively—and this is something that just occurred to me as I was listening to Mr. Chiles' testimony—the Commission could condition the allowance of 100-percent ownership of a qualifying facility by a utility, directly or indirectly, on their agreement to live with some kind of a speedy interconnect procedure. That idea is completely new, and I'm not sure how we would draft it, or how we would make it work. It is not inconceivable to me that the Commission, using a little bit of imagination, could come up with some sort of a solution.

Mr. Chairman, what I would like to do for a moment is defer to my general counsel on your question about the *AEP* case.

Mr. MOORE. The difficulty with the interconnect portion of the *AEP* case is there is no real good way to go. We believe, the Solicitor's office believes, and I believe that our petition before the District of Columbia Circuit on the interconnect rule is a valid argument. The difficulty is that section 210(3)(b) provides that no qualifying facility shall be exempt from the provisions of 210, 211, and 212 of the Federal Power Act. Both sides argue that it is ambiguous.

The difficulty with bringing the case back and trying to provide for a speedy hearing procedure, a statutory hearing, or a quick fix if you will, is you have to face the provisions of 210(3)(b).

While many will argue, and I disagree with them, that our interconnect order was invalid under 210(3)(b), it would be just as difficult to take the case back and try to provide for a hearing process that did not have to involve a full-blown evidentiary hearing on all the various substantive elements contained in 210, 211 and 212. Those issues are not addressed in the legislation which you have before you. I think it is something that you might wish to consider.

Mr. BUTLER. Mr. Chairman, 210(3)(b) is the provision in PURPA that requires an evidentiary hearing. One thing that you might consider—my recollection of 210(3)(b) when I was around as a staff member here in the Senate back when the statute was passed was that was something that the electric utility industry wanted very, very badly.

Now, it may be possible that some kind of a concession with respect to that language would be available from the industry as quid pro quo for your passing this statute that allows them to own 100 percent of qualifying facility.

In other words, you might be able to do directly what the Commission could only do using kind of a conditional procedure in a much less clean and effective way.

Senator HUMPHREY. Senator McClure has asked me to put this question to you, Mr. Butler. During consideration and passing of PURPA, it is my recollection that utilities were to be required to purchase only that energy in excess of the needs of the cogenerator. Is that currently the case, or are utilities purchasing all the energy produced by cogenerator at the utilities' avoided cost and selling back the cogenerators' needs to the utility?

Mr. BUTLER. I believe the latter is the case.

Senator HUMPHREY. How does FERC justify that result?

Mr. BUTLER. That's what the statute calls for if I'm not mistaken. I'm advised that I was wrong in saying that it was mandated by the statute. Their argument, as I understand it, was when the Commission made a decision— when the previous Commission made a decision—that was the only way to efficiently obtain all the available cogenerated electricity. I can't express agreement or disagreement with that.

Senator HUMPHREY. We will have a number of questions for you in writing and we will submit them to you. Thank you very much for your testimony.

We will now proceed to our first of two panels today. It will consist of Ms. Susan Shanaman, chairman, Pennsylvania Public Utility Commission; Mr. Ralph Mitchell, Arkansas Power & Light Co.; Mr. Frederic Greenman, New England Power Co.; and Mr. Steve Schaeffer, Houston Lighting & Power Co.

We would like you to begin, Ms. Shanaman. We have a number of witnesses this morning. Try to summarize your written testimony.

STATEMENT OF SUSAN M. SHANAMAN, CHAIRMAN, PENNSYLVANIA PUBLIC UTILITY COMMISSION

Ms. **Shanaman**. Thank you very much for permitting me to appear here today. I am the chairman of the Pennsylvania Public Utility Commission. I am testifying today on behalf of the National Association of Regulatory Utility Commissioners, commonly referred to as the NARUC.

As we understand it, Senate bill 1885 would repeal section 210's limitation on utility ownership of qualified cogeneration and small power facilities, thereby permitting utilities to receive the abovementioned benefits originally reserved for nonutility providers of electric power.

Under S. 1885 an electric utility would be free to establish the wholly owned unregulated subsidiary which would sell to its parent company power produced from qualified facilities. The subsidiary would then receive the avoided cost rate specified in the FERC regulations.

The apparent intent behind this proposed revision to PURPA's scheme for encouraging cogeneration and small power production is to eliminate utility opposition to the development of these supplemental power sources. It may also be perceived as a means to bolster the declining financial status of the electric utility industry, since it would open the door for the unregulated utility diversification within the electric power business.

However well-intentioned the bill's proponents may be, S. 1885 is decidedly not an appropriate means to accomplish those ends. Removing the restriction on utility ownership of qualified cogeneration and small power facilities may increase utility investment in these facilities; although there is no evidence that the 50-percent limitation is responsible for the utilities' lack of interest in such investment.

It would be misleading to characterize such a change as one which simply places utilities on an equal footing with nonutilities regarding investment in supplemental power sources.

On the contrary, S. 1885 would reinstate the inherent lack of market leverage which industrial cogenerators and small power producers share in relation to the electric utilities, and which PURPA's section 210 was designed to correct.

A most recent study which has not yet been published from the International Cogeneration Society indicates that in Pennsylvania there are 214 potential industrial cogenerators with about 2,400 megawatts of potential capacity. To put that capacity into prospective, Pennsylvania's electric utilities plan to add about 5,000 megawatts of new capacity in the 1980's.

In addition, by allowing electric utilities to engage in unregulated business ventures within the power business. A legislation would immensly complicate the task of State regulators whose responsibility it would be to insure that utility subsidiary transactions are at arm's length and not detrimental to the utilities' rate payers.

Since the cogeneration subsidiaries rate of return would be unregulated, the utilities' management would have a great incentive to invest capital in the subsidiary and neglect the utility, thus providing more profits for the stockholders.

The difficult job of policing any type of transaction between the utility and its subsidiary would be even more problematic if such transactions were to consist of utility purchase of power from itself.

At present State oversight of utility transactions with affiliated interest varies greatly. Some State Commissions are still in the process of developing specific accounting and reporting safeguards. Others have yet to establish their legal authority for exercising jurisdiction in this area. Even where procedural safeguards exist, few, if any, State Commissions are sufficiently prepared in terms of resources to deal with the oversight problems which the enactment of S. 1885 would create, and even increased resources would likely be inadequate to please less anti-competitive abuses such as passing the privileged information.

The members of NARUC do not oppose utility development of cogeneration. Indeed, some States have already adopted regulatory mechanisms such as preferred rates of return on equity, or expedited licensing procedures in order to encourage utility investing in energy efficient technologies.

Such incentives are within the context of the utilities' regulated operations, however, where we believe they should remain.

The only concern with incentives, the fact remains that a utility is legally obligated to provide electric service to its customers at the least cost of service. If it can accomplish this objective by investing in cogeneration of small power production, then that is what the utilities should be doing, regardless of whether PURPA authorized benefits are applicable to the investor.

A utility which is able to reduce cost for its rate payers by so investing should do so, or face exclusion of the excess cost of its rate base.

Although we submit that the 50 percent utility ownership limitation for the purpose of section 210 benefit eligibility has not been shown to have hindered utility investment in cogeneration and small power facilities, it is beyond dispute that implementation of PURPA is still at a very early stage in the States. It is conceivable that such a showing could be made as the statute's impact becomes discernable.

Assuming that the 50-percent limitation's detrimental effect can be demonstrated, the NARUC urges that the legislation repealing the limitation be foregone in favor of amending language to section 210 which would give the States discretion to grant utilities exemptions on a case-by-case basis.

These exemptions would be authorized only if the State Regulatory Commission with jurisdiction determines that a utility's greater than 50-percent ownership of qualified power facilities is likely to encourage cogeneration and small-power production without resulting in undue anticompetitive effects.

Adoption of such an amendment would carry with it advantages such as State regulatory jurisdiction over electric utilities would remain unimpaired; utility investment in unregulated cogeneration or small power facilities would be permitted to the extent that such investment does not jeopardize the interests of the monopoly ratepayers.

Included in the testimony is a suggested amendment. Utilities' diversification activities in cogeneration and small power production would be permitted only upon the exercise of the State commission's discretion, thus insuring that the same body which would be responsible for policing the utility-subsidiary relationship would make a decision to allow such a relationship to be established, with or without conditions or limitations.

With respect to comments on Senate bill 1966, we are supportive of elimination of that reporting requirement as being something that we are doing within the States, and would agree with the suggestion of the first witness from DOE that it could, in fact, be eliminated.

In addition to that, we would ask or suggest that it could be amended to also abolish section 309, thus eliminating the reporting requirement applicable to consideration of PURPA national gas related standards and, thereby, the need for form ERA-166. There is no reasonable justification for continuing to require States to report on the implementation of the PURPA standards for years after most States have completed that process.

This is particularly so in view of the purpose and nature of the data collection form which must be used to comply with the requirement.

I have referred earlier in the testimony to a need for a full evaluation of PURPA's actual impact before revision of its framework for encouraging energy conservation, use of energy efficient technology, and equitable utility rates for consumers is undertaken.

The NARUC intends to continue its contribution toward understanding in that regard by means of its annual survey of States' PURPA activities. This effort will go forward until such time as the record on this statute's effectiveness can be considered complete.

Thank you very much for your attention.

[The prepared statement of Ms. Shanaman follows:]

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY REGULATION

STATEMENT BY

SUSAN M. SHANAMAN, CHAIRMAN OF THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

FOR THE

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ON

S. 1885 AND S. 1966, BILLS TO AMEND THE
PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

APRIL 19, 1982

SUMMARY OF TESTIMONY

S. 1885

- Repeal of the 50 percent limitation on electric utility ownership of cogeneration and small power production facilities eligible for benefits under Section 210 is decidedly not an appropriate means to encourage cogeneration development or to aid the financial position of utilities.

- There is no evidence that utilities' lack of involvement in cogeneration or small power production is attributable to the 50 percent ownership limitation on utilities' qualified facilities under PURPA.

- By allowing an electric utility to establish a wholly-owned, unregulated subsidiary which would be free to sell to its parent company power produced from qualified facilities, the legislation's enactment would immensely complicate the task of State regulatory authorities. They would be responsible for ensuring that utility-subsidiary transactions are at arms-length and not detrimental to the utility's ratepayers.

- Currently, oversight of utility transactions with affiliates varies greatly. Even where procedural safeguards are available, few if any State commissions have the resources to deal with the policing problems which S. 1885's enactment would create. This is a particularly critical problem because a utility's management would have a great incentive to invest capital in the unregulated subsidiary and neglect the utility.

- A utility is legally obligated to provide electric service at the least cost of service. If it can accomplish this by investing in cogeneration, then this should be incentive enough to do so, regardless of whether PURPA's benefits are applicable to the investment.

- If the need for allowing utilities to own more than 50 percent of qualified facilities can be demonstrated, we suggest that in lieu of S. 1885, legislation be enacted that would permit State commissions to grant such exemptions as needed.

S. 1966

- As administered by the Department of Energy (DOE), the PURPA compliance reporting requirements which are applicable to the States have been unduly burdensome. The original form used to submit the data was needlessly complex, difficult to answer and provided little information ultimately used by DOE in its annual reports to Congress on this matter.

- DOE's revised form was recently streamlined, thus reducing the reporting burden. However, a number of its questions are not reflective of the actual PURPA standards consideration process as it occurs in the States.
- The NARUC has conducted annual surveys of the State's implementation of PURPA, an effort that will be continued as long as information on the statute's impact is deemed necessary.
- In view of these considerations, the NARUC supports enactment of S. 1966, and suggests that it be amended to eliminate the natural gas-related PURPA reporting requirements as well.

Good morning, Mr. Chairman and Members of the Subcommittee:

My name is Susan M. Shanaman. I am Chairman of the Pennsylvania Public Utility Commission, and I have been a member of the Commission since November 1979. I am testifying today on behalf of the National Association of Regulatory Utility Commissioners, commonly referred to as "the NARUC". Accompanying me today are Paul Rodgers, NARUC Administrative Director and General Counsel; Charles D. Gray, NARUC Assistant General Counsel; Rita A. Barmann, NARUC Director of Congressional Relations; and Donna S. Bolinger, NARUC Assistant Director of Congressional Relations.

The NARUC is a quasi-governmental, non-profit organization founded in 1889. Within our membership are the governmental agencies of the fifty States, the District of Columbia, Puerto Rico and the Virgin Islands which are engaged in the regulation of utilities and carriers. Our chief objective is to serve the consumer interest by seeking to improve the quality and effectiveness of public regulation in America.

More specifically, our members include those State officials who are charged with the duty of regulating electric and gas utility companies within their respective borders. As such, they have the obligation of assuring the establishment of such electric and gas utility services and facilities as may be required by the public convenience and necessity, and the furnishing of dependable service at rates that are just and reasonable.

We appreciate this opportunity to make known our views on the legislative proposals to amend the Public Utility Regulatory Policies Act of 1978,[1/] better known as PURPA, which are the focus

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[1/] Public Law 97-617, as codified at 16 U.S.C. 2601 *et seq*.

of today's hearing. As you know, the State regulatory commissions have been involved in the process of implementing PURPA since its enactment as part of the National Energy Act. We are therefore cognizant of the unique position which we occupy in evaluating the need for revising this statute. For reasons to be outlined later in my testimony, the NARUC supports enactment of S. 1966, a bill that would eliminate a reporting requirement concerning implementation of PURPA which is applicable to State regulatory commissions and non-regulated electric utilities.

We are concerned, however, that enactment of the other proposal, S. 1885, would significantly threaten the ability of the States to effectively regulate electric utilities and thereby protect the interests of the utility ratepayer. Moreover, achievement of the policy objectives underlying PURPA may be jeopardized by amending the statute before its impact has been fully evaluated. We urge, therefore, that S. 1885 be rejected. In the alternative, we suggest that the relevant provision in PURPA be amended so as to reflect the central principle advocated in S. 1885, while eliminating its unwarranted and counterproductive interference with State utility regulation and reducing the likelihood that achievement of the statute's goals may be undercut by further legislation before its effectiveness has been fairly tested.

S. 1885: Repeal of Utility Ownership Limitation

PURPA was enacted in 1978 in part to remove legislative, regulatory and institutional barriers that discourage the use of energy-efficient technologies such as cogeneration and small, non-utility power produced from renewable resources. Section 210 eases the environment within which cogenerators and small power producers operate in the following ways: (1) it exempts such qualified facilities from Federal and State utility rate and financial regulation; (2) it requires electric utilities to purchase power generated by these facilities and to sell electricity to them; (3) it requires that the power bought and sold by such facilities be compensated for at "just and reasonable rates" that do not discriminate against cogenerators and small power producers.

The statute expressly limits those eligible for these Section 210 benefits to non-utility power producers. It specifies that "qualified" cogeneration or small power facilities may not be owned by parties which are "primarily engaged in the production or sale of electric energy." The Federal Energy Regulatory Commission (FERC), which is charged with administering PURPA, has interpreted this limitation to mean that no more than 50 percent of a facility may be owned by an electric utility if it seeks the beneficial treatment granted under Section 210.

FERC regulations implementing Section 210's "just and reasonable" rates provision created a significant financial incentive for cogenerators and small power producers to seek "qualified facility" status. Under the regulations, each electric utility must purchase power from a qualifying facility at a level equivalent to the utility's "avoided cost", or the costs avoided by the utility by not having to generate the power itself. State commissions are prohibited from establishing tariffs applicable to cogeneration and small power sales to utilities which are below this standard.2/

2/ See 18 C.F.R. § 292.304. The FERC regulations on avoided cost were recently vacated by the U.S. Court of Appeals for the District of Columbia on the basis that the Commission failed to fully explain and justify its decision. See American Electric Power Service Corp., et al. v. FERC, et al., ____ F.2d ______ (January 22, 1982).

S. 1885 would repeal Section 210's limitation on utility ownership of qualified cogeneration and small power facilities, thereby permitting utilities to receive the above-mentioned benefits originally reserved for non-utility providers of electric power. Under S. 1885, an electric utility would be free to establish a wholly-owned, unregulated subsidiary which would sell to its parent company power produced from qualified facilities. The subsidiary would then receive the avoided cost rate specified in the FERC regulations.

The apparent intent behind this proposed revision to PURPA's scheme for encouraging cogeneration and small power production is to eliminate utility opposition to the development of these supplemental power sources. It may also be perceived as a means to bolster the declining financial status of the electric utility industry, since it would open the door for unregulated utility diversification within the electric power business.

However well-intentioned the bill's proponents may be, S. 1885 is decidedly not an appropriate means to accomplish those ends. Removing the restriction on utility ownership of qualified cogeneration and small power facilities may increase utility investment in these facilities (although there is no evidence that the 50 percent limitation is responsible for utilities' lack of interest in such investment). But it would be misleading to characterize such a change as one which simply places utilities on an equal footing with non-utilities regarding investment in supplemental power sources. On the contrary, S. 1885 would reinstate the inherent lack of market leverage which industrial cogenerators and small power producers share in relation to electric utilities, and which PURPA's Section 210 was designed to correct.

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In addition, by allowing electric utilities to engage in unregulated business ventures within the power business, the legislation would immensely complicate the task of State regulators, whose responsibility it would be to ensure that utility-subsidiary transactions are at arms-length and not detrimental to the utility's monopoly ratepayers. Since the cogeneration subsidiary's rate of return would be unregulated, the utility's management would have a great incentive to invest capital in the subsidiary and neglect the utility, thus producing more profits for the stockholders. The difficult job of policing any type of transaction between a utility and its subsidiary would be even more problematic if such transactions were to consist of utility purchases of power from itself.

At present, State oversight of utility transactions with affiliates varies greatly.[3/] Some State commissions are still in the process of developing specific accounting and reporting safeguards; others have yet to establish their legal authority for exercising jurisdiction in this area. Even where procedural safeguards exist, few if any State commissions are sufficiently prepared in terms of staff resources to deal with the oversight problems which enactment of S. 1885 would create. And even increased resources would likely be inadequate to police less obvious anticompetitive abuses, such as passing of privileged information.

The members of the NARUC do not oppose utility development of cogeneration. Indeed, some States have already adopted regulatory mechanisms such as preferred rates of return on equity or expedited licensing procedures in order to encourage utility investment

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[3/] See Appendix.

in energy-efficient technologies. Such incentives are within the context of the utility's regulated operations, however, where we believe they should remain.

Beyond this concern with incentives, the fact remains that a utility is legally obligated to provide electric service to its customers at the least cost of service. If it can accomplish this objective by investing in cogeneration or small power production, then that is what the utility should be doing, regardless of whether PURPA-authorized benefits are applicable to the investment. A utility which is able to reduce costs for its ratepayers by so investing should do so or face exclusion of the excess costs from its rate base.

Suggested Amendment In Lieu Of S. 1885

Although we submit that the 50 percent utility ownership limitation for the purpose of Section 210 benefit eligibility has not been shown to have hindered utility investment in cogeneration and small power facilities, it is beyond dispute that implementation of PURPA is still at a very early stage in the States. It is conceivable that such a showing could be made as the statute's impact becomes discernable. Assuming that the 50 percent limitation's detrimental effect can be demonstrated, the NARUC urges that legislation repealing the limitation be foregone in favor of amending language to Section 210 which would give the States discretion to grant utilities exemptions on a case-by-case basis. These exemptions would be authorized only if the State regulatory commission with jurisdiction determines that a utility's greater-than-50 pecent ownership of qualified power facilities is likely to encourage cogeneration and small power production without resulting in undue aticompetitive effects.[4]

Adoption of this suggested amendment to Section 210 would carry with it the following advantages:

- State regulatory jurisdiction over electric utilities would remain unimpaired.
- Utility investment in unregulated cogeneration or small power facilities would be permitted to the extent such investment does not jeopardize the interests of the monopoly ratepayers.

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[4] This amendment may be made by striking out paragraphs 1 and 2 of Section 210(e), by redesignating paragraph (3) as (4), and by inserting the following language immediately after "(e) EXEMPTIONS.-": "(1) Except as provided in paragraph 2, qualifying cogeneration and qualifying small power production facilities shall be exempt from the Federal Power Act, the Public Utility Holding Company Act, and from State laws and regulations respecting the rates, or respecting the financial or organizational regulation of electric utilities.

"(2) A qualifying small power production facility, or a qualifying cogeneration facility which is owned by a person primarily engaged in the generation or sale of electric power (other than electric power produced solely from cogeneration or small power production facilities) shall be exempted under paragraph (1) from any provision of law or rule or regulation referred to in paragraph 1 if each State regulatory authority with jurisdiction over that person's generation or sale of electric power determines, after public notice and hearing, that such exemption is likely to encourage cogeneration and small power production without resulting in undue anticompetitive effects or adverse consequences for that person's ratepayers. In providing such an exemption for any facility referred to in this paragraph, the State regulatory authority may provide such limitations or conditions as it deems necessary to carry out the purposes of this paragraph.

"(3) After consultation with State regulatory authorities, electric utilities, owners of cogeneration and small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral, as well as written data, views, and arguments, the Commission may promulgate such rules as it determines necessary to carry out the purposes of this subsection.".

- Utilities' diversification activities in cogeneration and small power production would be permitted only upon the exercise of the State commission's discretion (thus ensuring that the same body which would be responsible for policing the utility-subsidiary relationship would make the decision to allow such a relationship to be established, with or without conditions or limitations).

The essential point of our comments with respect to the proposal embodied in S. 1885 is that the development of cogeneration and renewable energy sources is not an end in itself, but rather a means to an end. The fundamental goal of statutes such as PURPA and of the efforts of State and Federal regulators, and, indeed, of the members of this Subcommittee in overseeing the Statute's implementation is the most efficient and economical use of our resources. Any statutory revision to the PURPA scheme must reflect this approach.

S. 1966: Eliminating the PURPA Compliance Reporting Requirement

Section 116 of PURPA requires that State regulatory authorities and nonregulated electric utilities submit to the Department of Energy (DOE) annual reports on their consideration of certain regulatory and ratemaking standards spelled out in Title I of the statute. DOE, in turn, is to submit an annual report to Congress on the States' implementation of the PURPA standards. Although the deadline for State compliance with PURPA occurred in November 1981, Section 116 requires that this annual reporting requirement extend into 1989.

A similar reporting requirement applies with respect to implementation of PURPA's Title III, which directs States and nonregulated gas utilities to consider employing certain ratemaking

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and other regulatory standards applicable to local distribution and retail sales of natural gas. Section 309 directs that State authorities and nonregulated utilities report to DOE, and DOE to Congress, on their consideration of these standards intended to encourage energy efficiency and equitable consumer rates. Like the reports required under Section 116, this requirement will not expire until 1989.

S. 1966, the second bill which is the subject of today's hearing, addresses only the first of these reporting obligations. It would repeal Section 116 of PURPA, effective after DOE submits its 1982 report on Title I compliance to Congress.

This is the fourth year during which the State commissions will be engaged in complying with what have undeniably been rather burdensome reporting requirements. Both are required to be submitted to DOE's Economic Regulatory Administration, or ERA, using its Form ERA-166. From the outset, the NARUC has been an active participant in efforts to improve the form, working through its Task Force on Form ERA-166 with ERA officials in a series of meetings from late 1979 through the summer of 1981. The thrust of our Task Force's comments was that the form was needlessly complex, difficult to answer, and that little of the information was actually used by DOE in its report to Congress on PURPA's implementation. On the other hand, the Task Force also relayed to ERA the view of some State commissioners that the form gathered much useful information.

Throughout our discussions with ERA, the NARUC Task Force pointed to the Association's own annual survey of States' PURPA activities as a model for revising Form ERA-166. The Task Force emphasized the simplicity, clarity and completeness of the NARUC survey and urged that ERA adopt a similar format. As pointed out by the General Accounting Office in a September 1981 report to Congress,[5/] the NARUC's annual report summarizing the results of its survey contained less detailed but more timely and cost-effective information on the State and utility PURPA consideration process.

The results of our input process have been mixed. Though as recently as June 1981 ERA expressed interest in adopting many of the NARUC's suggested changes in the reporting form, it went on to finalize its latest revision last month without consulting with the NARUC Task Force or the full Association.[6/] In addition, while the new form has been considerably streamlined, numerous questions contained in it remain unreflective of the actual PURPA standards consideration process as it occurs in the States. Such problems with accuracy and completeness are of genuine concern to the State commissions, since their efforts in discharging their PURPA obligations will be judged on the basis of evidence gleaned from this form.

In light of all of these considerations, the NARUC supports repeal of PURPA's Section 116, as contemplated by S. 1966. In addition, we respectfully suggest that the bill be amended to also abolish Section 309, thus eliminating the reporting requirement

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[5/] Comptroller General of the United States, "Burdensome and Unnecessary Reporting Requirements of the Public Utility Regulatory Policies Act Need to Be Changed," Report No. EMD-81-105 (September 14, 1981).

[6/] 47 Federal Register 11178 et seq. (March 15, 1982). ERA requested comments in this Notice of Proposed Rulemaking only as to the timing requirements of Form ERA-166, a finalized version of which was published as an Appendix to the notice.

applicable to consideration of PURPA's natural gas-related regulatory standards,[7/] and thereby the need for Form ERA-166. There is no reasonable justification for continuing to require States to report on their implementation of the PURPA standards for years after most States have completed that process. This is particularly so in view of the troublesome nature of the data collection form which must be used to comply with the requirement.

I referred earlier in my testimony to the need for a full evaluation of PURPA's actual impact before a revision of its framework for encouraging energy conservation, use of energy-efficient technology and equitable utility rates for consumers is undertaken. The NARUC intends to continue its contribution toward understanding in that regard by means of its annual survey of States' PURPA activities. This effort will go forward until such time as the record on this statute's effectiveness can be considered complete

Thank you very much for your attention.

7/ This amendment to S. 1966 may be made by striking in lines 3-6 on page one all language following "That" in line 3, up to and including "repealed." in line 6, and by inserting in lieu thereof the following language: "sections 116 and 309 of the Public Utility Regulatory Policies Act of 1978 are repealed."

"Sec. 2. The items relating to sections 116 and 309 in the table of contents in section 1(b) of such Act are repealed.

On page 2, line 2, the language "and under section 309(b)" should be inserted between "1982" and "of".

Appendix

Table 1a - TRANSACTIONS WITH AFFILIATES

AGENCY	The Agency prescribes special requirements for transactions with affiliates -	
	Accounting	Reporting
FCC and FERC	Prescribed system of accounts and annual report forms, require maintenance and reporting of separate accounts for investments in advances to, notes receivable from, accounts receivable from, advances from, notes payable to, and accounts payable to affiliates.	Same.
ALABAMA PSC	Yes.	Investigation by staff.
ALASKA PC	Policy not developed.	Policy not developed.
ALASKA PUC	Yes.	No limitation.
ALBERTA PUB	No special requirements established to date.	No special requirements established to date.
ARKANSAS PSC	Per system of accounts and annual reports; also same requirements as FERC and FCC, where applicable.	Same.
CALIFORNIA PUC	Accounting requirements same as FERC and FCC.	Same.
COLORADO PUC	—	Reasonableness of affiliate transactions are considered in rate cases.
CONNECTICUT DPUC		Service contract charges from affiliates are reported in the utilities' annual reports.
DELAWARE PSC	Accounting requirements same as FERC and FCC.	Reporting requirements same as FERC and FCC.
D.C. PSC	Any special accounting treatment it requires.	The Commission can set those reporting requirements necessary to carry out its statutory responsibilities.
FLORIDA PSC	Yes.	Yes.
HAWAII PUC	Yes.	Must submit consolidating statements with explanation of transactions and basis of allocation of common expenses.
IDAHO PUC		This commission does not have an affiliated interest statute.
ILLINOIS CC	Approval of all transactions except those specifically excluded by Sec. 8(a) of the Public Utilities Act.	File reports relative to such transactions as the commission may prescribe.
INDIANA PSC	Yes.	Yes.
IOWA SCC	Records of transactions must be preserved in the same manner as for the utility. Extraordinary documentation may be required and pricing is subject to greater scrutiny.	Same as FERC and FCC.
KANSAS SCC	Making adjustments for cases of ratemaking (Statute requires full disclosure).	Must identify related companies in annual report, file all contracts and keep Commission fully informed of transactions (required by statute).
LOUISIANA PSC	Yes, insofar as certain transactions are concerned.	
MAINE PUC	Only as occasion requires.	Only as occasion requires.
MARYLAND PSC	No special requirements prescribed would follow requirements of the uniform system of accounts and report forms.	
MASSACHUSETTS DPU	To the extent that they affect the regulated utility adversely.	Requires an abbreviated report form from each affiliate.
MICHIGAN PSC	Per system of accounts.	Yes, in rate case filing requirements and annual reports.
MINNESOTA PSC	Per system of accounts.	Part of Annual Report."
MISSISSIPPI PSC	No.	No.
MISSOURI PSC	Yes.	Yes.
MONTANA PSC	Must be absolutely separate.	All transactions are kept separately.
NEBRASKA PSC	All transactions deemed necessary by PSC.	Same.
NEVADA PSC		
NEW HAMPSHIRE PUC	Depends upon specific transactions.	Must submit various contracts which affect New Hampshire utilities - such as contract for services rendered and charged to utility.
NEW JERSEY BPU	Transaction must be reasonable and provide for elimination of unsupportable gains.	Description required to be given in annual report plus supplemental reports if deemed necessary.
NEW MEXICO PSC	Limited authority under new legislation to investigate certain subsidiary relationships.	
NEW YORK PSC	Companies required to keep accounts so as to be able to accurately and expeditiously produce statements of all transactions with associates.	Commission has authority under its general powers to require any special reports to keep the commission informed.
NORTH CAROLINA UC	The type and dollar amount of the goods and services represented by transactions between the regulated company and its affiliate must be identifiable in the books of account of the regulated company.	Annually the regulated companies must report the type, dollar amount and the name of the affiliate from which goods and services were received.
NORTH DAKOTA PSC	No prescription found necessary to date.	No prescription.
NOVA SCOTIA PUB	No special requirements established to date.	No special requirements established to date.
OHIO PUC	Commission has authority but no standards have been adopted. Not significant in Ohio.	Part of annual report. Commission has authority to require report.
OKLAHOMA CC	As required by uniform system of accounts.	Same.
ONTARIO EB	No special requirements established to date.	
OREGON PUC	Furnish detail of costs and no profit between affiliates.	File detail of all transactions showing costs and other pertinent data.
PENNSYLVANIA PUC	Commission has authority to approve acquisition by a public utility of 5 percent or more of the voting capital stock of any corporation.	Requires Commission Order within 30 days.
QUEBEC REB	No.	No.
RHODE ISLAND PUC	Yes.	Yes.
SOUTH CAROLINA PSC	All necessary steps to protect consumers.	Reports and other transactions filed and reviewed by the commission.
SOUTH DAKOTA PUC	Yes.	Yes.
TENNESSEE PSC	Yes.	Yes.
TEXAS PUC	Yes.	PUC has power to require any special reports to keep it informed.
UTAH PSC	There are no specific provisions in our law on these items but the commission is of the opinion it has adequate authority under the section of the law relating to accounts and records to prescribe such requirements.	Same.
VIRGIN ISLANDS PSC		Part of the Annual Report.
VIRGINIA SCC	Yes.	Yes.
WASHINGTON UTC	Maintain record of the cost of the services provided by the affiliate and if ascertainable the cost of all items sold to the utility.	All services and things should be provided at cost by the affiliate and annual reports of the cost thereof are filed with the commission.
WEST VIRGINIA PSC	As required by uniform system of accounts.	As required by annual report.
WISCONSIN PSC	Highly extensive.	Yes.
WYOMING PSC	Generally, complete separation of operations with only benefits flowing to utility.	Requirements patterned to facts of each case.

Appendix (from the 1980 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners)

Senator HUMPHREY. If utilities were permitted to own unregulated cogenerator subsidiaries, to what extent, in your opinion, would State PUC's take into account revenues from such subsidiaries in setting utility rates?

Ms. SHANAMAN. It's a very difficult question. I am sure the inclination of some States, particularly when you are having severe economic times and rates are continually rising and we are getting beat over the head constantly, would be to want to consider that.

I don't know to what extent States would consider them. I am sure the industry would not want us to consider them, as that would avoid the whole purpose of having that unregulated subsidiary.

I think the issue becomes one of not just in terms of the profits, but what happens if it's a loss situation, and what is the regulated industry going to want to do in that circumstance in terms of protecting? If you insulate the ratepayer from getting the profits, then you better insulate them from getting the loss.

Senator HUMPHREY. But the point of my question is that the PUC's could, in fact, take into account the revenues from the subsidiaries in setting rates. There is nothing to preclude them from doing that, isn't that correct?

Ms. SHANAMAN. I would have to say that's a "may". I'm not certain what every State's law states, and I am sure it would be a hotly contested issue in terms of just looking at Pennsylvania and whether or not we can consider those kinds of profits.

Senator HUMPHREY. Nothing in this bill impinges on PUC authority to set avoided cost rates; is that correct?

Ms. SHANAMAN. I believe that would be correct. In Pennsylvania we are currently in the process, and hope to have that completed within a couple of months.

As far as the generic rulemaking, we have a couple of utilities who are presently charging their avoided cost in cogeneration tariffs, and a couple of others for which we have extensive cogeneration tariffs on file.

Senator HUMPHREY. If it is the case that PUCs can still set the avoided cost price and if it is also likely that most of them could take into account the revenues from subsidiaries, what is your objection? I mean this bill does not, or isn't designed to, impinge on the authority of State PUCs.

Ms. SHANAMAN. I think the concern is that in effect it would be going around and deregulating industry, that to the extent that the industry would find it more profitable, and I would say profit is not a four letter word, but it certainly is all right, it's an OK goal for any kind of business to have. The concern would be to the extent that that is done, you could have self dealing, or you could have where that became more profitable, the utility putting more and more resources into that and sort of eliminating its commitment to the monopoly service which is currently serving the ratepayers.

Senator HUMPHREY. It is suggested as an alternative that the States be given authority to determine on a case-by-case basis when utilities might receive benefits under section 210. How long would such a process take?

Ms. SHANAMAN. I think that could depend upon the nature of the facility being in question, the kind of intervenors you had. Certainly I would say if you talked in terms of a 4- or 5-month period of time, that would be your minimum for any particular utility case.

Senator **Humphrey.** What is the average length of time now involved in a PUC rate case?

Ms. **Shanaman.** We have 7 months in which to determine what the utility's allowed revenues are under their requested rate case procedure.

Senator **Humphrey.** Is this 7 months a Pennsylvania figure? Is that some average or what?

Ms. **Shanaman.** That's a Pennsylvania figure. I do not know what the average is for across the country. If you would like, I am sure we could provide that information to you.

Senator **Humphrey.** Yes, that would be helpful.

Let us move on now to Mr. Mitchell. We will have your statement, and then we will go on to Mr. Greenman and then Mr. Schaeffer, and then we will go back to questions.

STATEMENT OF RALPH C. MITCHELL III, VICE PRESIDENT, CONSERVATION AND RENEWABLE RESOURCES, ARKANSAS POWER & LIGHT CO.

Mr. **Mitchell.** Thank you, Mr. Chairman. I am Ralph Mitchell, vice president of Conservation and Renewable Resources at Arkansas Power & Light Co., and I also serve as chairman of the Edison Electric Institute Issue Group on Cogeneration and Small Power Production. Both Mr. Greenman, vice president of New England Power Co. and Mr. Steve Schaeffer, manager of Rates and Research at Houston Lighting & Power Co. are members of that issue group and are joining me in presenting the testimony of Edison Electric Institute.

We do believe that the development of cogeneration and of small power production can make a significant contribution toward reducing our Nation's energy reliance on oil and natural gas. We believe that is the primary objective of the five statutes which comprise the National Energy Act of 1978.

In particular, PURPA authorizes removal of specific regulatory barriers and provides certain benefits to development of cogeneration facilities.

However, as Mr. Chiles developed this point earlier, it makes absolutely no sense to us that the industry in the best position to contribute to the development of cogeneration which we believe is the electric power industry is the only entity excluded from full participation in accomplishing that purpose.

No cogeneration facility which is more than 50 percent owned by an electric utility currently qualifies for those benefits PURPA provides.

We believe passage of Senate bill 1885 would remedy that situation and provide our industry with an equal competitive ownership opportunity.

We have already filed written testimony, Mr. Chairman, which supports our confirmed conviction that this is in the national interest. We have also taken time to review the pretrial testimony of the other participants in this hearing, and we feel that our written testimony adequately addresses some of the concerns expressed by some of those other speakers.

Therefore, rather than offer a synopsis of the testimony we have already filed, we plan to use this time this morning to discuss the benefits we believe would accrue to the public and to electric ratepayers from the passage of Senate bill 1885.

Each of us here today, Arkansas Power & Light Co.; New England Power Co.; and Houston Lighting & Power Co. have had some new experiences since the passage of PURPA which have helped us to come to that conclusion. I think perhaps a brief view of some of these experiences could be the most telling testimony we might deliver orally.

Taking Arkansas Power & Light first, immediately following the passage of PURPA we commissioned a study of some 1,500 oil- and gas-fire steam producers in Arkansas to determine the potential for cogeneration development, and also the likely actions that those steam users might take.

We found that among these 1,500 boilers, at least 35 were prime candidates for cogeneration. They represented something over 6 million pounds per hour of steam requirements used at a high-low factor, and a high volume at each. They were all major industrial firms in the wood and paper product industry, chemical and petroleum.

After identifying these 35 we began intensive interviews with each company to determine a likely course of action. We found each was well aware of the fuel use efficiency of cogeneration, and well aware of the incentives provided by Congress to promote this development.

However, we also discovered that none of those companies, with the possible exception of two paper product companies in Arkansas, was likely to make major new investments in cogeneration for one or more of four reasons.

First we found that industrial firms, like any other entity, including electric utilities, have finite capital resources available. Some firms simply did not have adequate capital to support their primary line of business much less a new sideline such as power generation. Some of those firms have done some economic analysis and found that cogeneration was, in fact, cost effective, but that the payback period exceeded their corporate criteria for the commitment of major new capital resources.

So, capital was one potential barrier to some of the industrial development. Second, we found some of the companies lacked the managerial, environmental, technical, or operating expertise to build on and operate cogeneration facilities; and particularly if they were going to be solid fuel like coal facilities.

A third and very significant deterrent is the finite increments of allowed development under air and water quality regulations as well as the availability of land resources.

Again, we found an industrial firm would prefer to use these limited resources to support its primary line of business rather than a power generation, and again, particularly solid fuel power generation.

Finally, in spite of PURPA, some companies remain concerned about possible ultimate exposure to price regulation.

This led my company to the obvious conclusion that more cogeneration potential would likely be developed in Arkansas if we, the electric utility, were allowed to participate. We have the experience with large capital intensive projects, with power generation technology, with solid fuel handling, use and waste disposal; and potentially we bring one additional source of capital for such projects.

However, to successfully compete in the steam market, we simply must be able to offer competitive price with that which can be offered by another party. Since there are only two revenue streams available to the cogenerator, the revenues from electricities and the revenues from steam, we would have to be allowed the same price on the electric output as that available to any other party in order to be able to price the steam output at a competitive price.

Also, if a project rate of return is regulated for a utility-owned facility and unregulated for the other party, then we are placed at a competitive disadvantage in attracting capital to our regulated venture.

Mr. Chairman, I would like to turn now to Fred Greenman from New England Power, and he is going to discuss some of the situations he has run into in the New England study.

STATEMENT OF FREDERIC E. GREENMAN, VICE PRESIDENT AND ASSOCIATE GENERAL COUNSEL, NEW ENGLAND POWER CO.

Mr. **Greenman**. Thank you, Mr. Chairman. My name is Frederic Greenman, vice president and associate general counsel of New England Power Co. which is the generating and transmission arm of New England electric system.

Our experience at New England Electric during the past year suggests that it is necessary to enact Senate 1885 in order to promote the development of qualifying facilities.

I think the best way for me to communicate to you why we feel this way is to outline the experience that we had in attempting to build the facility ourselves.

Our system has a 15-year corporate plan denominated as NEC plan. The key element of NEC plan is to promote the development of alternate energy sources in order for us to reduce our dependence upon oil.

The main element of our plan includes the construction of a 15 megawatt wood-burning cogenerating plant. To meet the qualifying facility requirements that exist today, it was necessary to find a partner willing to share equally in order to ship with us.

We started by identifying over 40 steam users in a territory which we hope to site this facility that we considered to be a potentially suitable candidate as a partner for this project.

We encountered a similar reaction to the one that Mr. Mitchell described at Arkansas. We found that while all of the steam users are very anxious, like all of us, to reduce their energy costs and enthusiastically and warmly greeted the idea that we might go forward with this facility, and initially expressed some interest in joining us, invariably we were told in the longer run that they were not in the position to shoulder a major ownership share.

The primary reasons were the same ones that Mr. Mitchell identified, unfamiliarity with energy production facilities, reluctance to invest whatever capital they had in a business that was unrelated to their existing operations.

It was only with great difficulty that we did manage, in the final analysis, to find a compatible partner for this project, and that was attributable, in part, to the fact that it was a site that was owned by a company that was a subsidiary of a company that has a great interest in energy facilities.

I can also testify that putting together an agreement between two partners, each having a 50–50 ownership of a qualifying facility, requires an extraordinary spirit of cooperation, and there are certainly formidable challenges associated with that kind of approach.

The lesson that we learned was clear. Nonutilities are reluctant to invest in cogeneration projects. They are uncomfortable putting money into projects that are foreign to their area of expertise.

On the other hand, utilities do such projects routinely and comfortably. Utilities possess the experience and the skills and, in fact, may tend to be willing to accept a more modest return on their investment than nonutilities in these kinds of transactions.

Thus, we believe that the 50-percent ownership limitation has an adverse effect on the advancement of cogeneration, and we believe that lifting this barrier to a full utility ownership will help in adancing the development of cogeneration.

Senator HUMPHREY. Thank you.

Mr. Shaeffer?

STATEMENT OF STEPHEN C. SCHAEFFER, MANAGER, RATES AND RESEARCH, HOUSTON LIGHTING & POWER CO.

Mr. SCHAEFFER. Thank you. My name is Steve Schaeffer. I am the manager of rates and research for Houston Lighting & Power Co., and we are here to support Senate bill 1885. We support the written testimony that EEI has filed in this matter.

My former job with the lighting company was involved in managing cogeneration projects, and only recently did I move into the rate area.

What I intended to do this morning was indicate some of the history that we had gone through in looking at different types of cogeneration projects, specifically one that was in the national news here not too long ago, was one with a major energy company.

We had arranged to find five or six low pressure steam users and had formed a partnership, a 50–50 partnership, for steam production with this energy company.

Because of the anxieties that both partners felt about regulation, we found a third partner, if you will, to own the high pressure steam facility which would have taken the high pressure steam and made electricity with it, and then sold the low pressure steam back to us for resale.

There were many issues that went into the development of that project that were affected by ownership arrangements, and the 50–50 partnership was certainly affected by language in PURPA. I can't promise you that if we had had different arrangements the project would have gone forward. It's unfortunately not going to go forward for many reasons.

It is clear to me that if we had had the ability to look at the project in a more unregulated light, that its potential for success would have been a great deal higher. That's not the only project that Houston Lighting & Power has looked at. We are in an area of the country where there are a large number of petro chemicals and a large number of major steam users. In fact, I am familiar with probably a million kilowatts of cogeneration that is in existence or under construction in my own service area now.

Our largest customer is also our largest cogenerator. They are presently making something like 600,000 kw of electricity on an hourly basis at their facility, and have recently applied to FERC for certification of that facility.

So you have a lot of research in cogeneration and have looked at it quite extensively. It is my belief, in our own case, there are certain small steam users who will not proceed with cogeneration projects on their own because it is outside the mainstream of their activity, and because it is not the highest priority on the list for expenditures.

In our own case we could go in with the smaller users, or with coalitions of multiple small users and perhaps build cogeneration projects similar to the one I mentioned to you, and I think the net benefit would be real, both in terms of fuel savings and in terms of benefit to the parent company.

So, for those reasons and for the other one I don't want to overlook, even in the partnership arena the 50-50 limitation casts a pull on utility involvement. It makes it less desirable to have a utility partner than a nonutility partner.

So, if we could compete in the marketplace on a more even basis, I think you will see more cogeneration. You will see smaller people involved in cogeneration, and perhaps you will see even more partnership projects where the balance may not be 50-50. Maybe it will be 60-40, or maybe it will be 70-30, or whatever.

So, along that note, I would like to restate my thanks for you listening to me this afternoon and restate my support for S. 1885.

[The prepared statements of Mr. Mitchell, Mr. Greenman, and Mr. Schaeffer follow:]

STATEMENT BY EDISON ELECTRIC INSTITUTE

Comments in Support of S. 1885 to Provide Electric Utilities Equal Competitive Ownership Opportunities with Respect to Cogeneration and Small Power Production

Presented by

Ralph C. Mitchell, III
Vice President
Conservation & Renewable Resources
Arkansas Power & Light Company

and

Frederic E. Greenman
Vice President and Associate General Counsel
New England Power Company

and

Stephen C. Schaeffer
Manager-Rates and Research
Houston Lighting & Power Company

Before the Subcommittee on Energy Regulation
of the Senate Committee
on Energy and Natural Resources

April 19, 1982

STATEMENT BY EDISON ELECTRIC INSTITUTE

I. Introduction

Mr. Chairman and members of the Committee, I appreciate the opportunity to appear before you to discuss the subject of cogeneration and, in particular, the issue of equal treatment for electric utility ownership of cogeneration facilities. I am Ralph C. Mitchell, III; Vice President, Conservation & Renewable Resources for Arkansas Power & Light Company, (AP&L), Little Rock, Arkansas, and Chairman of the Edison Electric Institute (EEI) Issue Group on Cogeneration and Small Power Production which is a group of electric utility representatives formed to monitor legislative and regulatory developments in cogeneration and small power production. I am assisted here today by Fred Greenman, Vice President and Associate General Counsel of New England Power Company, the generation and transmission subsidiary of New England Electric System, and Steve Schaeffer, Manager of Rates and Research for Houston Lighting & Power Company. Mr. Greenman and Mr. Schaeffer are also members of the EEI Issue Group. This testimony is presented on behalf of AP&L, which is one of the operating companies of the Middle South Utilities System, the New England Power Company, Houston Lighting & Power Company, and EEI.

Cogeneration has a potentially important and beneficial role in our nation's energy future. EEI supports cogeneration as a means of energy conservation wherever it will reduce the nation's dependence upon oil and natural gas. We believe that the goal of our nation's energy policy is to facilitate the transition from an energy economy historically based on cheap, abundant supplies of oil--much of which is imported--and natural gas to one in which the use of scarce and imported fuels is restrained and increasing use is made of coal and other domestically available energy resources, as well as energy conservation.1/ In many cases, cogeneration can assist in satisfying this national goal. However, the current legislative and regulatory environment is not conducive to the most effective and efficient deployment of cogeneration technology. In particular, the Public Utility Regulatory Policies Act of 1978 (PURPA), which authorizes removal of certain regulatory barriers and provides certain benefits to developers of cogeneration and small power production facilities, excludes from these benefits facilities in which electric utilities own greater than a 50 percent equity interest. EEI supports S. 1885, introduced by the Chairman of this committee, Senator Humphrey, and cosponsored by Senator Johnston, which removes this barrier to equal, competitive ownership opportunities on the part of electric utilities.

II. Description of Current Ownership Limitation

Sections 3(17) and 3(18) of the Federal Power Act, added by Section 201 of PURPA, define a qualifying cogeneration or small power production facility as a facility which the Federal Energy Regulatory Commission (FERC) determines by rule meets such requirements (including size, fuel use, fuel efficiency, and reliability) as the FERC may prescribe, and "which is owned by a person not primarily engaged in the generation or sale of electric power...." Section 210(e) of PURPA authorizes the FERC to exempt cogeneration and small power production facilities which receive "qualifying facility" (QF) status from certain sections of the

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1/ While EEI recognizes that both gas and oil supplies are currently adequate, and that the price of oil has declined during the past several months, we firmly believe that the electric utility industry must plan for the integration of coal and domestically available alternative fuels into long-term resource plans.

Federal Power Act, the Public Utility Holding Company Act of 1935, and from state laws and regulations respecting rate, financial, or organizational regulation of electric utilities.

The regulations issued by FERC pursuant to Sections 201 and 210 of PURPA grant QF status to cogeneration and small power production facilities in which electric utilities and any affiliated companies together have no greater than a 50 percent equity interest, exempt QFs from state regulation regarding utility rates, financing, and organization, from Federal regulation under the Federal Power Act (other than licensing under Part I and Sections 210-212 of Part II), and from classification as an electric utility under the Public Utility Holding Company Act of 1935. In addition, QFs are entitled as a result of the FERC rules to sell power to utilities at "full avoided cost" rates. Full avoided costs are defined as those costs which the utility would otherwise have to incur absent the power generated by the QF.1/

The primary intent of the PURPA-mandated rules is to encourage the development of cogeneration and small power production facilities by removing regulatory constraints to such development (i.e., deregulation of QF generation) and by providing incentives to such development by pricing power purchases from QFs at the utility's incremental or marginal cost. The rules ensure that electric utilities will purchase power from QFs as long as such purchases are priced no higher than the utility's true avoided cost (in effect providing a guaranteed market for QF electric output.)

1/ A recent decision by the United States Court of Appeals for the District of Columbia Circuit, American Electric Power Service Corp. v. FERC, No. 80-1789 (decided Jan. 22, 1982, rehearing denied April 9, 1982) vacated and remanded the full avoided cost rule, but this decision is still subject to possible appeal to the Supreme Court.

EEI believes that PURPA was intended to properly encourage the development of facilities which reduce our reliance on scarce fuels --oil and natural gas-- and make more efficient use of our resources. Such actions will achieve the primary goals of our national energy policy-the reduction of scarce fuel imports and preservation of diminishing domestic resources. We find limitations on electric utility ownership of QFs, which impede the development of these facilities, to be counterproductive to these national policy goals. As will be explained in our testimony today, EEI supports S. 1885 as legislation that is consistent with the intent of PURPA and the nation's energy policy by removing barriers to electric utility ownership of cogeneration and small power production facilities.

III. Electric Utility Interest in Cogeneration and Small Power Production

As this Committee is well aware, the electric utility industry is facing a rapidly changing operating environment. EEI believes that one of our most critical national needs is to make the transition from an economy historically based on low-cost and abundant supplies of oil and natural gas to increased reliance on coal and alternative energy sources. The electric utility industry will be a prime contributor to this transition. However, continuing to meet such a goal requires tremendous levels of capital at a time of extremely high interest rates and insufficient rate increases to maintain investor-owned utilities in a financially healthy position. These economic conditions are causing many electric utilities to incorporate new options in their resource plans as a means of (1) continuing to provide adequate, reliable, and low-cost service to customers and (2) providing adequate returns to investors to ensure a continued influx of the necessary capital to meet the industry's needs. Many utilities have seen cogeneration and small power production as an important element of an overall program to meet these dual goals.

For example, at Arkansas Power & Light we are exploring the concept of gasification of solid fuels to produce medium BTU gas for pipeline transmission to the "on-site" cogeneration facility. Incorporated in this concept is the use of combined-cycle cogeneration facilities, which will substantially enhance the efficiency of fuel utilization of the system through the increased electrical capacity associated with a fixed steam requirement.

Concerning the integration of cogeneration and small power production into electric utility resource plans, Florida Power Corporation is undertaking cogeneration projects with major industrial customers in the phosphate mining and processing industries. It is also studying the potential use of biomass and solar energy as part of its overall long-range resource plans.

Southern California Edison has set a goal to provide approximately one-third of its projected additional generating capacity during the next 10 years from alternative energy sources which include cogeneration, wind, geothermal, solar, and small hydroelectric facilities.

Cogeneration is also a principal focus of San Diego Gas & Electric's wholly-owned subsidiary, Applied Energy Inc. (AEI). AEI operates four cogeneration facilities which are capable of producing nearly 61 megawatts of electric generation and furnishing 510,000 pounds of steam per hour for industrial purposes. Through heat recovery equipment, AEI utilizes an additional one-third of the heating value of the fuel which would otherwise be wasted.

Gulf States Utilities, serving portions of Texas and Louisiana, has been a pioneer in the use of cogeneration technology since its Baton Rouge plant became operational in 1929. This facility has an electric generation capacity of 100 megawatts and supplies between 15 and 19 billion pounds of steam annually. The company has made a commitment to develop an additional 300 megawatts of cogeneration in the 1980s. If this goal is realized, it is possible that the need for a 300 megawatt unit planned for the late 1980s can be deferred, saving $300 million in construction costs.

Last year, Niagara Mohawk Power Corporation organized a subsidiary to promote the development of cogeneration and hydroelectric power. This subsidiary was established pursuant to a New York statute [Public Service Law Section 66-c (1980)] which provided for the establishment by electric utilities of unregulated cogeneration and small power production subsidiaries. The newly formed company will jointly undertake projects with an affiliate of the Consolidated Natural Gas Company.

These are just a few examples of how electric utilities are moving to incorporate cogeneration and small power production developments into their long-range resource plans in response to changing conditions in the industry. However, the ability of electric utilities to fully develop the cogeneration and small power production potential is seriously impaired and the attractiveness of fully pursuing these technologies is inhibited by the current 50 percent ownership limitation. Furthermore, the current PURPA limitation is an impediment to the most efficient and effective deployment of this technology, discriminates against electric utilities, and runs counter to the public interest. In the remainder of our testimony, we will address some of the benefits that will result from removal of the PURPA ownership limitation and respond to some of the arguments against equal, competitive ownership opportunities for electric utilities which have been presented in the past.

IV. The Electric Utility Role

Since passage of PURPA in 1978, substantial interest in cogeneration and small power production facilities has been generated. Through April 1 of this year, the FERC has received qualifying facility applications for 3,000 MW of cogeneration capacity and 1,400 MW of small power production capacity, for a total of 4,400 MW. Only about 60 percent of this total, however, represents new facilities, and a number of these proposed facilities will likely not be constructed due to lack of financing. However, to put this renewed interest in cogeneration and small power production in perspective, the percentage of total generation from these sources has declined over the past twenty years. 1/

With respect to cogeneration in particular, a recent study by Resource Planning Associates, Inc. (RPA) for the Department

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1/ "Plugging Cogenerators Into the Grid", EPRI Journal, July/August 1981.

of Energy estimated that the economically feasible maximum cogeneration development in the five major steam-using industries will be 15,500 MW between 1980 and 1990.1/ However, the report points out that not all of the economically feasible potential will materialize, and actual investment will likely fall in the range of 6,200 - 12,800 MW. Thus, it appears that industry, relying solely on its own capital resources, is likely to develop only 40-80 percent of the full cogeneration potential.

The reasons for industry's recognized reluctance to make all cost-effective investments in cogeneration are many. They include capital limitations for investments which are not in the primary line of business, uncertainty of demand and price for power and steam needs, technical risks, the company's overall market position and financial health, unacceptable payback from the investment, uncertain price and availability of fuels, land requirements, environmental limitations, and lack of expertise with the technology. Exhibit 1 presents the results of an EEI survey of thirteen industrial companies with cogeneration potential. Of these thirteen, four currently have cogeneration facilities, and two have such facilities in the planning stages. The table summarizes some of the inhibiting factors to cogeneration investment on the part of the surveyed companies.

In general, economic factors were seen as presenting the major sources of discouragement. The fact that power generation is not their main line of business leads some firms to attach a low priority to generation investments versus those more crucial to their main product line. Available capital and credit is often insufficient to

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1/ The Potential for Industrial Cogeneration by 1990, Resource Planning Associates, Inc., July 31, 1981.

support the main business of an entity, much less support entry into a new business, power generation. Many companies also expressed a requirement for a higher rate of return and shorter payback period for investments not in their primary line of business (i.e. power generation) relative to investments in main line productive capacity. Thus, many dispersed energy investments which might look attractive to utilities, are considered unattractive by industrials. Companies are also inhibited by uncertainty with regard to the long-term prices of electricity and steam; they view this uncertainty as increasing the risk that they will not be able to achieve an acceptable payback on the project.

Technical factors were also commonly cited as inhibiting industrial cogeneration investment. One very significant deterrent to industrial cogeneration is the finite increments of allowed development under air and water quality regulations, as well as availability of land resources. An industrial firm would prefer to use these limited resources to pursue its primary line of business, rather than power generation -- particularly power generation using solid fuels. Furthermore, as a consequence of power generation not being the companies' main line of business, many felt that they lacked the technical and managerial expertise required for selection, construction, and operation of cogeneration plants.

EEI believes that many of these economic and technical barriers to cogeneration investment can be overcome by encouraging electric utility participation in the market. Because of their experience with many cogeneration and small power production technologies, utilities have the technical, managerial, and financial expertise needed to develop the market further.

Utilities have two characteristics important to the development of cogeneration: First, experience with the operation of coal and other type boilers, environmental protection equipment, fuel procurement and handling, and waste disposal; and second, unique knowledge of the energy consumption patterns of their customers and frequent contact with them. This experience and knowledge should be utilized. Consumer confidence in the technical abilities of utilities, as well as their permanence, make them an ideal institution to promote the development of cogeneration.

The RPA study, cited earlier, estimates an additional 4,000-8,000 MW of electric utility investment in industrial cogeneration would result from removal of the PURPA electric utility ownership limitation. There would likely be additional small power production development as well. RPA has estimated the total additional cogeneration and small power production capacity with equal utility ownership opportunities at 8,000-12,000 MW by 1990.

If cogeneration and small power production technologies are to achieve their full market potential, electric utilities must be given equal, competitive ownership opportunities--which would be accomplished by S. 1885. It is obvious that continued cost-of-service regulation of electric utility investments, while all others can receive revenues based on the utility's incremental costs for those investments, puts utilities at a competitive disadvantage.

There are two main reasons an electric utility cogeneration entity must have the same incentives that PURPA provides for an industrial-owned facility. First, the industrial firm is clearly interested in steam at a competitive cost. There are only two revenue streams to the cogenerator--electricity and steam sales. If an industrial-owned facility sells its electrical output to the electric utility system at a rate based on avoided cost, but an electric utility-owned cogeneration facility receives less than avoided cost for electrical output, the electric utility would necessarily have to price the steam at a higher and consequently less competitive rate. The potential industrial customer is simply not interested in a noncompetitive steam price offering.

Second, if the project rate of return is regulated for a utility-owned facility and unregulated for an industrial-owned facility, then it is likely that given a choice between these two entities, an investor would seek the investment that provides the higher return on capital. Under existing legislation, utilities are at a competitive disadvantage in attracting investment capital for project financing of cogeneration facilities.

Removal of the PURPA restriction on electric utility ownership of QFs would extend to electric utilities a critical benefit which is now available to all other QFs--the opportunity to price its electrical product at market value throughout the life of the facility. The FERC rules under Section 210 of PURPA provide QFs the right to sell their electrical product at a price which is based on the avoided cost of the purchaser--i.e., the cost that the purchasing electric utility would have incurred but for the purchase from the QF. This is in essence a market value price, which is allowed to change with time as the avoided costs of the purchasing utility change.

Regulated electric utility investments, by contrast, may only obtain a limited rate of return on the original investment cost of a generating unit less accumulated depreciation. It is this opportunity to price the QFs' electric product based on the market value established by the alternatives available to the purchasing electric utility--an opportunity available to every other person with respect to QFs--which is critical to the equal, competitive opportunity sought by electric utilities.

The current ownership limitation may also distort long-run economic planning decisions which must take into account the cost, reliability, and availability of all potential sources of electric power. Current limitations on utility ownership distort the economic planning decisions of electric utilities in several ways. First, many cogeneration and small power production technologies are new and involve higher risks than conventional generation technologies. By limiting utilities to a regulated rate of return, they will not have the incentive to invest in dispersed energy facilities with higher risks. Second, for cogeneration to be economic for utility investments there must be an assured continuous steam demand. To the extent that fluctuations in the business cycle or business failures increase the uncertainty of steam demand, risk to the utility and its ratepayers is further increased.

Continued cost-of-service regulation of electric utility dispersed energy investments also makes such investments ineligible for energy tax credits. To the extent that the energy tax credits were intended to promote dispersed energy investments and reflect increased risk, we see no reason why electric utility investments in these same technologies should be excluded from the same tax benefits available to anyone else. This discrimination against electric utilties is unjustified and could be remedied by eliminating cost-of-service regulation for these technologies.

V. Benefits of Equal Competitive Ownership Opportunities

In addition to the encouragement of further cogeneration and small power production development discussed above, the removal of the PURPA ownership limitation will produce several other benefits. Electric utilities, in choosing investments, are likely to be more sensitive to the requirements of utility customers and the public interest. For example, utilities are more likely than industrials to use coal or alternative fuels for cogeneration, as part of an overall program to reduce utility reliance on oil and natural gas. Utilities have much more experience with the use of coal technologies and associated environmental considerations than do industrials. In addition, some electric utilities (including Arkansas Power & Light) are developing synthetic fuel (from coal) applications for cogeneration which involve higher than normal risks. The greater risks and capital costs associated with these technologies often permit their deployment only if the electrical and thermal products can be priced at market value throughout the facility's existence.

Furthermore, there are many different cogeneration technologies available to meet a given steam demand. Certain technologies (which primarily use oil and gas) have higher electric to thermal ratios than others, thus producing more power for a given steam requirement. In choosing a cogeneration system to serve a particular industrial steam requirement, a utility would consider optimization of net oil and gas use, electrical output, and reliability for the total system. An industrial firm does not have the same incentive to maximize the benefits of a cogeneration facility to the electric utility system, and thus the ratepayer.

Incentives for utility ownership of cogeneration will also benefit small industrial or commercial concerns. While such small users might not find it economical or feasible to invest in cogeneration matched to their thermal requirements alone, a third party could find it advantageous to cogenerate for a cluster of smaller users. Utilities, relying on their knowledge of small users and their technical expertise, would be the ideal facilitator for such cogeneration projects.

Even for larger steam users, multi-user cogeneration projects have proven difficult to effect. A 1979 study by Kidder, Peabody & Company suggests that although economies of scale can be achieved by increasing the number of parties using the output of a cogeneration facility, organizing such a venture is highly complex.1/ Electric utilities, based on their technical, managerial, and financial expertise, are well positioned to serve as the owner and developer of such complex, multi-user projects, but the ownership limitation is a barrier.

VI. Responses to Concerns About Electric Utility Ownership of QFs

In our discussions with both legislators and regulators concerning the effects of S. 1885, several common themes have

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1/ Financial Considerations Affecting Implementation of a Large Multiparty Cogeneration Project, Kidder, Peabody & Company, Inc., April 1979.

been mentioned as possible negative consequences of equal, competitive electric utility ownership opportunities for cogeneration and small power production. In this section of our testimony, we would like to dispel these concerns about electric utility ownership of QFs.

One concern which has been expressed is that allowing equal ownership opportunities under PURPA will result in anti-competitive practices on the part of electric utilities. S. 1885 will not change the PURPA requirements for utilities to purchase power from any cogenerator or small power producer at up to incremental cost and sell power to them at non-discriminatory rates. Thus, utilities will be barred from refusing to purchase power from qualifying facilities owned by others.

Additionally, utilities do not have any natural monopoly advantage with respect to cogeneration and small power production development. In fact, with respect to cogeneration, industrial facilities have a natural monopsony in that they have the captive demand for steam. An industrial steam user has sole decision authority over whether to produce his own steam requirement or from whom to purchase that requirement. With respect to hydroelectric projects, municipalities and public agencies have a preference right to development, and others are permitted by FERC primarily on a first-come, first-served basis. For resource recovery (trash-burning) projects, municipalities or other governmental jurisdictions which collect the refuse have the competitive advantage.

Some concern has also been expressed that utilities will attempt to pay higher rates for purchases from qualifying facilities owned by them than for QFs owned by others, will manipulate avoided cost calculations to benefit unregulated investments, or will favor affiliated QFs with respect to interconnection practices and cost recovery. State commissions, as well as the FERC, currently have jurisdiction to disallow purchased power expenses which are imprudently incurred as well as broad authority to remedy unjust, unreasonable and unduly discriminatory practices. In addition, a utility's avoided costs are subject to public as well as regulatory scrutiny, in the context of both state commission review of utility expansion plans and state proceedings relative to implementation of PURPA Section 210. Thus, any attempt on the part of the utilities to favor their own projects relative to others will be subject to close regulatory scrutiny. Finally, since electric utilities will be participating in a competitive market, they will also be subject to all laws restricting unfair trade practices.

EEI believes that there are sufficient mechanisms presently in place to protect against possible anti-competitive practices on the part of electric utilities should the ownership limitation of PURPA be removed. Case-by-case review by the FERC or state commissions, which would be administratively burdensome and unworkable, should not be a pre-requisite to qualifying status, nor are statutory limitations on utility ownership necessary to prevent anti-competitive practices. The proper forum for review and remedy of such practices is state commission proceedings (either generic or upon complaint) to consider utility practices and contracts with respect to unaffiliated versus affiliated QFs.

A final concern is that utilities will attempt to expand the definition of a qualifying cogeneration facility to "deregulate" existing or planned generation. Existing generating units owned by electric utilities and already included in rate base would require state commission or FERC approval for sale or transfer to an unregulated subsidiary. Such a transaction must satisfy a public interest test and would, of course, be subject to close regulatory scrutiny.

New generating units would have to meet the operating and efficiency standards of FERC Order No. 70 implementing PURPA to become a qualifying cogeneration facility. This standard requires that the useful thermal energy output for topping-cycle facilities be no less than 5 percent of the total energy output. In an order applying this standard, the FERC found that use of thermal energy for aquaculture was not a useful thermal energy output.1/ In fact, the FERC stated in its order that "If a conventional powerplant could become a cogeneration facility simply by culturing warm water fish in the condenser discharge, than most, if not all, power plants could claim cogeneration status." Thus, we believe FERC authority is currently sufficient to prevent electric utilities from using removal of the ownership limitation on QFs as a means of escaping cost-of-service regulation by building in non-useful thermal energy outputs, as this example points out.

VII. Conclusions

Based on the testimony which we have presented today, EEI believes that removal of the current PURPA electric utility ownership limitation, which would be accomplished by S. 1885, is in the national interest, and would serve to improve our economy's energy efficiency and reduce our dependence on scarce and imported sources

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1/ EG&G, Inc., Order Granting Application for Certification as a Qualifying Cogeneration Facility, FERC Docket No. QF81-13-000, July 21, 1981.

of fuel. We believe that providing equal, competitive ownership opportunities for electric utility investments in cogeneration and small power production facilities will have the following benefits for the nation:

(1) Greater realization of the total cogeneration and small power production market than would otherwise be the case.

(2) More efficient integration of dispersed energy facilities into electric utility resource plans.

(3) More rapid development of advanced technologies such as advanced coal combustion systems, advanced combined cycle generation, coal gasification, fuel cells, and solar applications.

(4) Greater use of coal and alternate fuels in cogeneration facilities.

(5) Greater development of cogeneration applications for multiple industrial and commerical steam users in the same geographic area.

We also believe that S. 1885 is consistent with the purposes and goals of PURPA which are to encourage (1) the conservation of energy supplied by electric utilities, (2) the optimization of the efficiency of use of facilities and resources by electric utilities, and (3) equitable rates to electric consumers.

Exhibit 1

Results of EEI Discussions with Industry

Factors Inhibiting Industrial Cogeneration Investment

INDUSTRY	COGENERATION													
	PLANNING	YES	NO	LIMITED	ENVIRONMENTAL	CAPITAL	POWER/ STEAM DEMAND	UNCERTAINTY OF LONG-TERM PRICING	NOT MAIN BUSINESS	TECHNICAL RISK	STATE OF BUSINESS	STANDBY RATES	UNACCEPTABLE PAYBACK	FUEL $'STR AVLBL
1		✓			X	X								
2	✓				XX									
3		✓			XX			XX						
4			✓				XX							
5			✓				XX				XX			
6			✓			X	XX					X		
7	✓				X									
8			✓			XX				XX			XX	
9				✓		XX		XX			XX			
10			✓			XX			XX					X
11		✓			X									
12				✓		XX			XX		XX			
13		✓						X						

LEGEND: X = Relatively Minor Factor

XX = Relatively major Factor

Mr. MITCHELL. Mr. Chairman, could I briefly summarize our points that we want to make? I think primarily we are trying to say that Senate bill 1885 we think would lead to more cogeneration than would otherwise be the case, clearly.

I might point out that is not based just on our experience and our opinion, that there have been a number of studies which would confirm this. DOE has commissioned studies by such reputable firms as Argon National Labs and Resource Planning Associates who have reached the same conclusion.

So has the Electric Power Research Institute, through its own work and some studies it has had commissioned by consultants such as Energy Resources.

I would urge you also to consult the Congressional Office of Technology Assessment Cogeneration Report which should be concluded about now, and should address this issue as well.

I think, second, we feel that utility involvement would lead to more rapid development of the advanced technologies such as advanced coal combustion systems, advanced combined cycle generation, coal gasification, fuel cells, and solar facilities. This should lead to greater use of coal in particular, but also our other alternative fuel forms to oil and natural gas. We believe there would be greater development of coal generation application for multiple industrial and commercial small steam users in the same geographic area since the electric utility is perhaps the prime institution available to promote and develop such multiple user systems.

Finally, I think my industry is much more likely to insure that utility customers also benefit beyond simply the reduction in our Nation's reliance on oil and natural gas. We have consistently stood by setting the maximum rate at which a qualified facility sells power to the regulated electric utility, so that the electric rate-payer will always receive a benefit, regardless of the ownership of the facility, utility, or otherwise.

I would also think that an electric utility would attempt to optimize the electrical output from serving a given thermal requirement and the reliability of a cogeneration facility to the electric grid who simply does not have the same incentive to serve the electric grid power. Thank you.

Senator HUMPHREY. Mr. Mitchell, you mentioned a number of studies a moment ago. Can you make those available to us for inclusion in the record?

Mr. MITCHELL. Certainly we will.

[Excerpts of the studies submitted by Mr. Mitchell follow:]

The Potential for Industrial Cogeneration Development by 1990

Final Report

RPA Reference No.: RA-81-1455

prepared for
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July 31, 1981

Deregulation of 100-Percent Utility-Owned Plants

Currently, electric utilities have a limited financial incentive to invest in cogeneration. The allowed return on investment in a number of small cogeneration plants would be no greater than that allowed for one equivalent large central station plant, while the administrative costs and dispatching constraints are less attractive than for a large central station plant. Although PURPA allows utilities up to a 50-percent unregulated ownership, as mentioned earlier, joint-investment agreements are much harder to effect than single-party ownership.

Yet there are several advantages to utility ownership. Utilities are in business to supply electric power and are inherently more comfortable with the operation of power plants. Utilities also have considerable experience in dealing with legislation such as FUA, NGPA, and PURPA. Utilities often can purchase coal and other fuels at lower prices than industrials, particularly if done in concert with purchasing for the whole system. Perhaps most important, it is likely that the financial requirements of utilities are more favorable to cogeneration than those of industry. Although a deregulated utility may desire the same high return on investment that an industrial demands, the normal rate of return for new investments by a utility is much lower than for an industrial -- 12-15 percent compared to over 30 percent for many industrials. Therefore, many utilities will have a lower hurdle rate and in many cases can produce electricity and sell steam to the industrial at a price lower than the industrial could produce itself. In addition, the utility may accept a longer life for the equipment. If an industrial decides to shut down a manufacturing process served by cogeneration equipment, the utility might find a use for some of the equipment in some other part of its system.

On the basis of our interviews, we believe that allowing utilities to compete for unregulated generation investments on the same basis as industrials would provide utility managers with a strong business incentive that could produce attractive benefits for their shareholders and strengthen their financial position, which in turn would help financing for their regulated business. Although it is difficult to estimate a precise impact from such an incentive, given the wide differences in utility reserve margins, load forecasts, potential for cogeneration by service area, financial position, and management philosophy, we think the impact could add 4,000 MW or more to cogeneration in the five industries by 1990. This would occur because of the following three changes.

1. A shift in the future cogeneration technology mix towards greater electric-to-thermal output systems. To the extent a utility replaces an industrial as a cogeneration plant investor, the utility would be more interested in selecting a combustion turbine or combined-cycle plant to maximize the electric power output, given the importance of that selection to its overall business. Our analysis shows that in cases where a boiler-steam turbine is the most attractive technology, the combustion-turbine and combined-cycle technologies are often nearly as attractive. Utilities in service areas that need new capacity, which tend to be areas with more attractive economics for combustion turbines and combined-cycle plants, would make the tradeoff of a slightly lower return on investment to gain significantly more electric power. (Exhibit 2.j shows the significant higher

Exhibit 2.j

Output Characteristics of Cogeneration Technology/Fuel Combinations

Technology	Fuels	Electric to Thermal Output Ratio (kW/000 lbs steam/hr)
Boiler with steam turbine	Coal • Direct • AFB Residual fuel oil Natural gas Black liquor	20–60
Gas turbine with waste-heat boiler	Distillate fuel oil Natural gas Synthetic gas	130–210
Combined cycle	Distillate fuel oil Natural gas Synthetic gas	350–400

electric-to-thermal output ratios of the combustion-turbine and combined-cycle plant technologies). If just 10 percent of the boiler-steam turbine technologies were shifted to combustion-turbine and combined-cycle plant technologies (in a ratio of two-thirds combustion turbines to one-third combined-cycle plants) the amount of cogenerated power would increase more than 2,000 MW (see Exhibit 2.k).

2. Stimulation of additional investments in industrial cogeneration. About 25 percent of the technically feasible cogeneration in the five industries would not receive investment by industrial companies. If one-fifth of this additional potential were realized (5 percent of the total technical potential), an additional 1,000 MW of cogeneration would occur by 1990, assuming the same mix of technologies as in our base case (see Exhibit 2.k). The estimate of 5-percent additional development of the technical potential is based on the amount of development constrained by capital limitations or lack of awareness of cogeneration on the part of industrial managers.

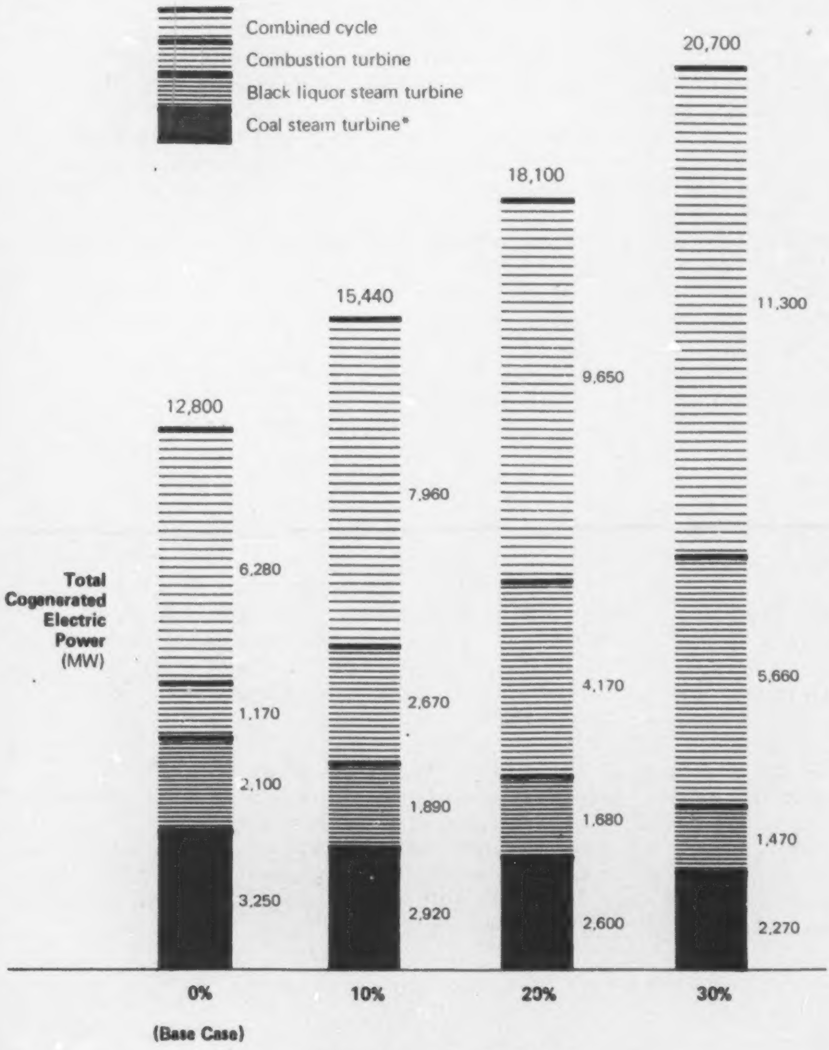
3. Establishment of more explicit and, in some cases, higher avoided-cost tariffs by participating utilities. While PURPA requires that utilities establish tariffs for buyback rates equal to their highest avoided costs of power, a number of utilities and PUCs are adopting a case-by-case approach to cogeneration, and are not setting explicit buyback rates. The absence of explicit rates in a tariff produces greater investment uncertainty for industrial investors than would otherwise be the case and either eliminates the investment or shifts the decision to a lower electric-to-thermal technology. But if an unregulated utility owner would benefit from higher avoided-cost levels, that utility would have a greater incentive to set rates at the highest possible level for all consistent with the requirements of PURPA.

In some states, utilities and PUCs expressed a desire to set buyback rates at some level below the utility's full avoided cost in order to share some of the benefit with other electric power consumers. Even in this situation, no matter what the buyback rate would be under regulated utility ownership, if ownership were deregulated some utilities would have a greater incentive to set rates as high as possible within the "share the savings" guidelines. The effect would be similar in nature to the buyback situation in which there is a limit on allowing full avoided costs.

Exhibit 2.k

Effect of Change in Cogeneration Technology Mix on Electric Power Capacity by 1990 in the Five Major Industries

(MW)



Percent of Steam Turbines Replaced by Combustion Turbines and Combined Cycles as a Result of Utility Ownership

* Includes coil boilers and atmospheric fluidized-bed boilers.

A question naturally arises as to whether a utility could improperly set buyback rates so high that its unregulated subsidiary would benefit at the expense of ratepayers of the regulated utility. We do not think this would happen under PURPA because the buyback rate is regulated by the PUC; PURPA's legal mandate does not allow the commission to approve any rate higher than the costs the regulated utility would avoid by not generating the power itself or purchasing it elsewhere. Further, the rate published by the regulated utility for purchase of cogenerated power would apply to all cogenerators and small power producers in its service area. With regard to these other owners, the utility would have an incentive to ensure that the rate is no higher than its full avoided costs.

The effect of having more explicit and perhaps somewhat higher avoided-cost tariffs in some utility service areas across the country is hard to predict without a utility-by-utility analysis. Nevertheless, as described at the end of Chapter 1, the impact of higher avoided-cost rates can be significant. Further, the areas of the country where utility ownership would be most likely (i.e., areas with the greatest need for new capacity) are areas close to the economic threshold that produces the most favorable economics for combustion turbines and combined-cycle plants. Although the potential from setting more explicit and somewhat higher avoided-cost tariffs could be quite significant, there is substantial uncertainty about it. On the basis of a region-by-region analysis, our conservative estimate is that an additional 1,000 MW-3,000 MW of power could be cogenerated.

The effect of the above three factors would be to add 4,000 MW or more to power cogenerated in the five industries by 1990. Of all the governmental actions of possible value, we think full deregulation of utility ownership has the greatest potential impact and deserves concerted action by federal and state legislators and regulators to bring it about.

Utilities in Crisis: A Problem in Governance

Alvin L. Alm
Daniel A. Dreyfus

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Table of Contents

Introduction and Summary 1
The Crisis Develops 5
Objectives and Options 22
Conclusions and Recommendations 44
Forum Participants 54
Forum Program 58

This report on Utilities in Crisis: A Problem in Governance reflects the authors' understanding of the broad consensus of the participants at the July 11 - 16, 1981, Energy Policy Forum in Aspen, Colorado. All participants had an opportunity to comment on the draft, and some expressed reservations over some aspects. While many participated in the thoughts in this document, the authors take full responsibility for its contents.

Alvin L. Alm
Daniel A. Dreyfus

INTRODUCTION AND SUMMARY

The electric utility industry faces a financial crisis. Whether measured by the ratio of stock price to book value, rates of return, or credit ratings, the industry is in real trouble.

The Nature of the Financial Crisis

Trouble began to plague the industry at the beginning of the last decade. In 1970, the declining cost curve for producing electricity started to reverse into the familiar U-shaped curve that afflicts a number of U.S. industries. During 1973-74, prices for two major fuels for utilities, oil and coal, rose precipitously. Nuclear plants, which once showed such promise for reducing costs, began costing more to construct as schedules were delayed, more safety measures were necessary, and financing costs began to increase. The fixed cost of overcapacity, a result of high electricity rates dampening growth, was spread over existing consumers, again increasing their rates. Rising interest costs and inflation added to the industry's misery, particularly for utilities with nuclear plants in the pipeline, and regulatory and siting problems added to utility costs. As utility costs increased, regulators began tightening the reins on utility rates and cash flow, leading to many of the financial problems utilities face today.

While it is obvious that utilities face a financial crisis, it is not as obvious that their predicament is a problem of governance. Why should there be pervasive concern over the future of the utility industry, an industry that does not face foreign competition, cannot leave the country, and will always be around in some form?

The National Interest. There are important reasons for this concern. First, failure to provide utilities with the ability to attract capital --

resulting in neglect of investment -- can only bear bitter fruit in the future, whether in the form of higher rates from costly generating facilities and fuels or in deteriorating service. One need only remember the downward spiral of railroad service, as revenues became insufficient to finance needed capital improvements. Second, rather than allowing service to deteriorate for all customers, some utilities or regulatory bodies may decide industrial growth can no longer be served. Failure of utilities to provide service or providing undependable service may have the same effect of encouraging firms to locate abroad. Third, many decisions to defer capital expenditures result in higher costs in the long run, shifting these costs to future generations. Intergenerational transfers are a fitting subject for public policy concern. Fourth, in many cases failure to provide utilities with adequate capital has resulted in greater oil use, increasing U.S. vulnerability to an oil supply interruption.

The Expectations of the Stakeholders. There is no quick fix to the utilities' plight, a problem that has been growing for some time. Its solution is particularly illusive because stakeholders expect different things from utilities. The utility executives want to go back to the era when they had the flexibility to meet future growth requirements. The stockholders want to see a reversal in the erosion of the value of their stock. Ratepayers want a stop to rising electricity bills and preferably a decline. Public interest groups have various expectations, from cancellation of nuclear power plants, use of soft energy systems, to lifeline rates. Industry fears rate systems that will subsidize residential users at their expense. The public utility commissions are caught in the middle of these competing claims, mindful of utilities' financial problems but also buffeted by consumer outrage over high bills. The result is a system that is not really satisfactory to any of the participants and is leading to a weakening of utilities' financial position.

Recommendations

To get out of this mess, some political consensus will be necessary. All the participants would have to adhere, at least in some respects, to generic goals for the nation's utility system. While many such goals could be articulated, the following four are the most obvious and important:

- o Electricity cost increases should be held to a minimum.
- o The electric system should be reliable.
- o Oil use should be reduced.
- o Rates of return should be comparable with other investments of similar risk.

To achieve these objectives, the report recommends a broad range of actions to be carried out by public utility commissions, the utilities, and the Federal government.

The Public Utility Commissions should:

- o Grant rate relief so that utilities can make a rate of return comparable to equivalent types of investments and in a timely fashion.
- o Provide greater incentive for innovation by reducing regulatory control over utilities and establishing more performance based incentive ratemaking in the future.
- o Encourage coal conversion through positive financial incentives.
- o Experiment with less regulation.
- o Change accounting practices that discourage cost-effective investments.
- o Disseminate information on regulatory innovations.

The Utilities should:

- o Pursue a least cost strategy by employing a range of supply options, as well as by employing measures to reduce capacity and energy demand.

- Communicate better with the public by informing them of progress being made to reduce costs.
- Stage new capacity investments to avoid temporary overcapacity.
- Improve reliability through participation in power pools and other ways of spreading outage risks.
- Take steps to convert formerly coal-capable plants back to coal and accelerate new projects to further reduce oil use.

The Federal Government should:

- Allow utilities to participate fully in the benefits offered by cogeneration and small power projects by the Public Utility Regulatory Policies Act through elimination of the restriction on full utility ownership.
- Expedite the process of licensing nuclear plants, without sacrificing health and safety protection.
- Push regulatory reform through Federal Energy Regulatory Commission initiation of incentive ratemaking proposals and through encouraging successful proposals by state commissions, as well as considering the desirability of deregulating wholesale rates.

These recommendations are aimed at achieving the four goals and at least roughly satisfying the various stakeholders. Ironically, it will probably be easier to cope with the financial and technical concerns facing the utilities than with the divergence of perceptions, interests, and outlooks of the major participants. Creating a political consensus among these diverse groups will not be easy.

SRC REPORT NO. 7070-R1

UTILITY PARTICIPATION IN
DEUS PROJECTS:
REGULATORY AND FINANCIAL ASPECTS

FINAL REPORT

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November 1981

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Section 5

ALTERNATIVE FINANCIAL STRUCTURES FOR ELECTRIC UTILITY PARTICIPATION IN DUAL ENERGY USE SYSTEMS

OVERVIEW OF UTILITY PARTICIPATION

The current regulatory environment provides opportunities for electric utilities to participate in dual energy use systems projects. Participation may range from mandatory purchase and sale of power with PURPA qualified small power producers to 100% utility ownership of DEUS projects. The approach that is taken depends upon the financial condition of the utility, its ability to use tax credits, present and future load characteristics matched against internal plans to supply these capacity requirements, and external factors including the condition of the financial markets and the utility's state regulatory environment.

This report has been prepared in a period of rapid change and uncertainty. The Reagan administration has shifted emphasis from conservation to increasing energy supply and has recommended the early elimination of energy tax credits. The U.S. Supreme Court is expected to decide the constitutionality of PURPA Title I, Title III and Section 210 in early 1982, while the states are in the process of implementing PURPA related regulations. Proposed legislation may lift electric utility ownership limits on qualifying cogeneration facilities, while raising the energy tax credit to 20% on a broader list of property for a longer period of time. This environment creates opportunities, while at the same time increases the risks associated with utility participation.

Cogeneration projects are a natural extension of the electric utility business and can become a planned segment of a utility's future generation mix. The individual utility can actively shape the development of cogeneration in its service area, or be reactive and have uncoordinated development take place. The current Public Utility Regulatory Policies Act defines criteria for cogeneration that exempt the project from all state and federal financial and rate regulation. However, each state's regulatory environment will determine if the higher rates of return earned by utilities participating in qualified cogeneration projects will be comingled with regulated earnings.

OWNERSHIP OPTIONS

The ownership options described in the following sections are for investor owned electric utilities. The rules for publicly owned and municipal utilities are different and are addressed only where specifically noted. The electric utility can participate in cogeneration projects in many different ways as shown in Figure 5-1. There is no prohibition against an electric utility owning 100% of a cogeneration facility, even though it would not qualify for tax incentives or relief from regulatory reporting requirements and rate of return limits. Joint ventures with utility ownership of more than 50% but less than 100% of a cogeneration facility are unlikely, since the project would be subject to utility regulation, would involve multi-party arrangements, and would not receive the tax incentives that could attract outside ownership. Joint ventures with utility ownership of 50% or less of a cogeneration project are more favorable since tax benefits can be utilized to reduce capital costs and unregulated rates of return can be earned.* The utility may be involved in cogeneration projects without ownership.

Most cogeneration projects to date have been developed by industry acting without utility ownership. Under PURPA, utilities are required to provide service to these projects and purchase their electric output. The power purchase contract may be used to help secure project financing and thus the utility facilitates the project without an ownership interest. The project may also be developed by a third party and leased to the utility so that the utility has no ownership interest in the project. Under this arrangement the lessee gives up the benefits of property ownership and tax credits in return for lower capital requirements and capital costs.

USE OF SUBSIDIARIES FOR COGENERATION PROJECT DEVELOPMENT

The electric utility may participate directly in a cogeneration project or through a wholly owned subsidiary. A subsidiary could limit potential corporate liability of the parent to the amount of its investment in the subsidiary. If the utility

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*It may be necessary for the utility to own the qualifying facility through a bona fide subsidiary in order to obtain the tax benefits.

UTILITY OPTION	UTILITY OWNERSHIP	PURPA IMPACT	FINANCING IMPACT ON UTILITY
Sole Ownership	100%	Not a qualifying facility, ineligible for tax credits, avoided costs and reporting benefits.	All capital must be raised by the utility at its cost of capital.
Joint Venture	Greater than 50% but less than 100%.	Same as above.	Shared capital requirements but no tax credits to reduce cost of utility capital.
	50% or Less	Qualifying facility eligible tax credits, avoided costs and reporting benefits.*	Shared capital requirements, tax credits may reduce cost of capital and may attract third party financing.*
No Ownership	0% Ownership Interest.	Same as above.	No utility capital required - Project leasing may be an option.

Figure 5-1. Ownership Options for Electric Utility Participation in Cogeneration Projects.

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*It may be necessary for the utility to own the qualifying facility through a bona fide subsidiary in order to obtain the tax benefits.

owned the cogeneration project directly, the project's creditors would have claim on all the utility's assets. If utility ownership was through a subsidiary, project creditors would be limited to the subsidiary's assets so the most the utility would lose would be its investment in the subsidiary.

A wholly owned electric utility subsidiary for cogeneration project development, operation and ownership provides substantial non-financial benefits. The subsidiary provides a focus for organizing utility cogeneration strategy, activities, responsibility and control. The subsidiary would also serve as the primary utility vehicle for communicating with potential cogenerators, regulators and the public. The subsidiary may be necessary in order to obtain the tax benefits.

The use of a subsidiary for cogeneration project ownership by an electric utility does not provide a vehicle to exceed PURPA ownership limits. The 50% or less ownership limit by electric utilities includes the sum of all electric utilities and subsidiaries of electric utilities and/or public utility holding companies. If a subsidiary of an electric utility was established as a vehicle to own 50% or less interest in one or more cogeneration projects, then those projects and the subsidiary would be exempt from federal and state rate and financial reporting, and would be eligible for tax credits. If the subsidiary owned more than 50% interest in one or more cogeneration projects, then those projects and the subsidiary would be regulated.

CONSIDERATIONS FOR UTILITY PARTICIPATION IN COGENERATION PROJECTS

Public utilities have a number of internal and external considerations to review in order to decide how to participate in cogeneration projects. The internal factors include the extent of current and planned investment in new capacity, the ability to raise capital, the cost of that capital, the ability of the utility to use tax credits and the effect of the cogeneration project on the average costs and rate of return.

Accounting Considerations

A major utility concern is the impact of financing cogeneration projects on its ability to raise capital now and in the future. The accounting treatment of debt and required debt equity ratios have led many utilities to use project financing or equipment leasing to keep additional debt off its balance sheet.

Utilities may be required to maintain a relationship of debt to equity for statutory purposes. Raising debt to finance any projects can add to the utility's debt burden and may trigger the need to sell common stock in unfavorable markets. This may dilute the value of the share held by existing stockholders. Some sources of debt capital will require that the utility maintain a debt coverage ratio.* This ratio is a margin of safety for the creditors but may limit future borrowings by the utility. Project financing uses the project's assets, future cash flows, contracts, etc., to secure the debt rather than the utility raising a pool of funds itself and dividing them among its projects. Third party project financing can be structured to keep the debt off the utility's books, but credit effects of the project commitments are not eliminated.

Project financing is not a substitute for credit and is not a panecea for financing all utility cogeneration projects. Project financing and other innovative approaches will not make uneconomic projects financeable, but will make good projects more competitive in obtaining financing. Non-financial institutions such as major cogeneration component equipment manufacturers may be a source of off balance sheet financing through turn-key plant leasing. The equipment manufacturers look to the credit of the utility to secure the lease, even though the lease does not appear on the utility's balance sheets.

External Considerations

The external considerations for utility participation in cogeneration projects include the projected electric demand growth in its territory, the state regulatory environment and the state of the financial markets. Slower demand growth may make smaller increments of new capacity additions, such as cogeneration, suitable for matching future capacity needs. The regulatory environment can provide incentives for cogeneration development, or it can create uncertainty which makes financing difficult or impossible. Some states may attempt to recapture unregulated earnings for the benefit of the ratepayers, while others may encourage unregulated activities as a means of improving the utility's financial condition at no expense to the ratepayer. The State of Mississippi has sued in federal court to overturn the whole PURPA process creating uncertainty for utility cogeneration joint venture in that state.

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*Debt coverage ratio = net income plus non-cash expenses divided by debt service.

The financial markets are in flux. Traditional private placement financing sources including insurance companies and pension funds have been forced to change their definitions of prudent investments. Fixed rate long-term debt from these sources may not be available or may require indexing or equity participation. The fluctuation in interest rates has been historically rapid resulting in difficulty in marketing debt issues.

An individual electric utility can participate in cogeneration projects in the way best suited to its financial position, market growth and regulatory environment. Each utility has a culture in which all plant decisions are evaluated. The same set of conditions that dictate direct ownership of all generating capacity at some utilities, may allow partial ownership to gain the benefits of unregulated operations at other utilities, and suggest that leasing the project assets is the best approach for another group of utilities. The cost of raising capital for some utilities is prohibitive so project financing may be the only viable option to participate in cogeneration. Other utilities that have the ability to raise capital want to modify the regulatory environment to allow them to own 100% of the cogeneration projects in their service area. The best option or approach for utility participation must be determined by each utility.

SOLE OWNERSHIP BY AN ELECTRIC UTILITY

Sole ownership of a cogeneration project by an electric utility has several benefits. The utility has complete control of the project in both the developmental and operational phases. This results in the same benefits as the development and operation of any new generating facility in its system. The main advantages of sole utility ownership are control over design, construction and operation of the facility. Utility personnel have the expertise to select the equipment, supervise its installation and operate it once completed. Utilities have experience in arranging the acquisition of long-term fuel requirements, fuel transportation and fuel handling systems, including the disposal of fuel wastes. Utilities are familiar with the permitting and reporting requirements for siting new power plant facilities, and have reporting systems in place to meet regulatory requirements.

Utility ownership of new generating equipment increases the utility's rate base and allows for larger total profits, although limited to a fixed percentage of investment. Cogeneration projects can be part of a consistent long-range plan to provide the capacity required in the service area. This consistent approach can minimize the loss of desirable base loads and be coordinated with other major central station generation projects.

The disadvantages of sole utility ownership of cogeneration projects center on the financial condition of the utility and its planned construction expenditures. The financing capacities of utilities are strained by regulatory delays in providing rate relief at the same time new plant costs are escalating and lead times are lengthening. Cogeneration projects may cost more per kilowatt than large central electric generation projects, while requiring the same amount of siting studies and other development costs. The utility's limited capital must be allocated to the optimum mix of electric generation capacity required to meet the loads in its territory. Cogeneration may be part of the optimum generating mix and, if so, should be developed in a planned fashion along with other projects.

The major disadvantage of sole ownership by an electric utility are the opportunity costs of lost tax credits and the potential for higher returns from operating the cogeneration project as an unregulated business. As a result, sole ownership should be limited to cases where joint ownership allowing qualifying facility status cannot be obtained. District heating and cogeneration from new power plants for multiple thermal loads as part of planned industrial parks may only be feasible through sole utility ownership. Figure 5-2 summarizes the advantages and disadvantages of sole utility ownership of cogeneration projects.

SOLE OWNERSHIP BY THE INDUSTRIAL USER

Most cogeneration projects have been developed by individual industrial firms to provide thermal process energy and some or all of their electrical requirements. The advantages of sole ownership include all the equity earnings and tax benefits from the project. If the tax benefits cannot be used by the corporation, it could become a sole lessee and the tax benefits can be claimed by the lessor in return for lower lease costs. As with sole utility ownership, sole ownership by the industrial user provides a large degree of management control over the sizing, design, construction, timing and operation of the facility. In some cases, the cogeneration system can utilize waste products from the industrial processes resulting in fuel and waste removal savings.

The disadvantages of sole ownership by the industrial cogenerator relate to the use of scarce capital and other resources. The firm must bear the entire capital burden which may limit the funds available for investment in the primary productive capacity of the business. Most firms do not have the staff expertise to operate and maintain power generating equipment, and do not want to have additional employees that are not directly related to primary production

ADVANTAGES

- Control of design, timing and operation.
- Previous experience in design, construction and operation.
- Previous experience in fuel acquisition and handling.
- Existing systems in place for reporting.
- Addition to rate base.
- Coordinated with other planned additions.

DISADVANTAGES

- More capital required for cogeneration than electric alone.
- Requires guarantee of thermal sales to make it economical.
- Inability to gain or use tax credits.
- Earnings are limited to regulated rate of return.

IMPLICATIONS FOR UTILITY PARTICIPATION

Utilities may be sole owners of projects where the number of thermal users is large, a new power plant is needed in the immediate vicinity and other financing alternatives are not possible. District heating and multiple user industrial parks would be typical projects solely owned by the utility.

Figure 5-2. Advantages and Disadvantages of Sole Utility Ownership of Cogeneration Projects.

activities. An industrial plant may have a constraint on its total pollutant emissions. Thus, the firm may have to choose between installing a cogeneration project and another activity such as expanding its output. The ownership of a cogeneration project may not produce returns equal to typical industrial returns on capital. If internal hurdle rates (opportunity costs of capital) are not met, the industry would be unwilling to invest in the project. Many industries set higher hurdle rates for projects that are outside of their primary business.

The advantages and disadvantages of sole industrial ownership of a cogeneration project are summarized in Figure 5-3.

SOLE OWNERSHIP BY THIRD PARTIES

Cogeneration projects could be owned solely by a third party that would sell the thermal energy to an industrial firm and the electricity to the utility. Sole ownership by third parties does occur when the equipment manufacturers, contractors, architectural and engineering firms or unrelated passive investors* form entities to finance, own and operate a cogeneration project as a business. Third party ownership is most likely to occur when the utility and the industrial firm or other participants cannot use the tax credits effectively. In most cases, the ownership risks of a large scale cogeneration project are too great for third party ownership unless the risk is passed to the energy purchasers through long term contractual purchasing agreements or leases. The likelihood of third party sole ownership that retains all the risks of ownership is very small.

Leasing Versus Buying

Whichever company or joint venture operates a cogeneration facility, it must choose between leasing the facility from third parties and owning it outright. We may assume that the operating revenues or cost savings from a project will be the same either way. The problem then becomes that of selecting the method which has the lowest total cost over the life of the project discounted for when those costs

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*The recently enacted "at risk" rules contain substantial requirements which affect the desirability of these investments to investors, Subchapter S corporations and certain other closely held corporations.

ADVANTAGES

- Control of design, timing and operation.
- Use of waste resources as fuels.
- Availability of investment and energy tax credits.
- Savings in total energy costs.
- Opportunity to arbitrage sale of power at avoided cost and purchase power at average system costs.

DISADVANTAGES

- Current regulations may be changed.
- Scarce capital.
- Additional expertise required for cogeneration operation.
- Use of air pollution emission limits.
- Lower rate of return than primary business.

IMPLICATIONS FOR UTILITY PARTICIPATION

Industry should be interested in joint venture arrangements with utilities to minimize their sole ownership disadvantages. Industry would be particularly interested in utility participation to share total project capital costs and to utilize the expertise of utility personnel.

Figure 5-3. Advantages and Disadvantages of Sole Industrial Ownership of a Cogeneration Project

are incurred. The cost of a leased asset is the present value of the after tax lease payments over the term of the lease. The total cost of owning the asset is its purchase cost, less the value of the tax deductions for depreciation over its life, investment and energy tax credits, and residual or salvage value at the end of its life. If some of the funds to purchase the asset are borrowed, then the cost is further reduced by the value of the tax deductions for interest payments which is also known as the tax shield of debt financing. This assumes that the borrowed funds and their repayments are discounted by the borrower at the same rate as the interest rate on the loan, and that therefore the net present value of the principal of the loan is zero.

To a company considering leasing equipment instead of buying it, the maximum lease payment will theoretically be just equal to the net cost of owning over the term of the lease. Similarly, from a lessor's point of view, the minimum lease receipts should at least cover the costs of ownership, discounted at a rate which includes normal return on investment. Therefore, financial theory can demonstrate that in a competitive capital market, lease charges should be such that users of assets are indifferent as to whether they own or lease the assets. A number of assumptions have to be made for this to be true, particularly: the lessors and lessees have equal costs of capital, equal tax rates, therefore, equal values of tax deductions, and that both have taxable income so that both can take advantage of tax credits.

Since large amounts of assets are leased in the modern economy, it is obvious that these assumptions do not always apply. Utilities and industrial users of cogeneration equipment are likely to have higher costs of capital than leasing firms, therefore, leasing may be advantageous.

The Economic Recovery Tax Act of 1981 will result in increased tax oriented lease transactions. The new law permits the transfer of investment tax credits, energy tax credits and tax depreciation between taxpayers. This will result in a new kind of investor called a nominal lessor which may be any company which is subject to federal income tax. The nominal lessor will buy the tax credits and depreciation associated with equipment from a firm that does not have tax liability and cannot use the credits and depreciation. The nominal lessor gets the tax advantages and the lessee gets the use of the equipment at a reduced purchased price. Cogeneration property that is eligible for both energy tax credits and investment tax credits would be attractive candidates for a tax shelter lease involving a nominal lessor.

Impact of Leasing

Related to cost of capital is the issue of debt capacity. Leasing is often regarded as a form of "off-balance sheet" financing if future lease payments need not be shown as liabilities on the balance sheet, but debt incurred to purchase the equipment would be. This may be important to utilities, many of which already have as much debt in their capital structure as financial prudence and their regulatory agencies will allow.

Off-balance sheet financing through leasing and leveraged leasing is very complex. The agreements to structure the obligations in a manner which qualifies for favorable tax treatment are arranged by investment bankers and tax lawyers. The lease financing agreements differ from case to case. This section provides an overview of asset leasing.

Theoretically, lenders would examine the total obligations of a utility or other company, whether they took the form of debt service or lease payments. Therefore, there would be no "debt capacity" advantage to leasing. In fact, accounting rules are making it increasingly difficult to avoid showing lease obligations as liabilities on the balance sheet. But, if certain conditions are met, it can still be done. Therefore, leasing retains some of the advantage of off-balance sheet financing.

As for the tax advantages of accelerated depreciation, interest deductions and tax credits, operators of cogeneration facilities may not necessarily be able to take full advantage of them. Utilities in particular are already very capital-intensive, and therefore may have all the depreciation deductions and investment tax credits they can use. Other investors, especially those in high tax brackets, may be able to make better use of those deductions and credits, and pass some of them on to the operators by leasing.

A schematic flow diagram of leveraged lease financing is presented in Figure 5-4 and the advantages and disadvantages of third party ownership are presented in Figure 5-5.

MULTI-PARTY APPROACHES

The main theoretical justification for a multi-party approach is to share the risk of a project. This reduces the total risk to any one participant, while

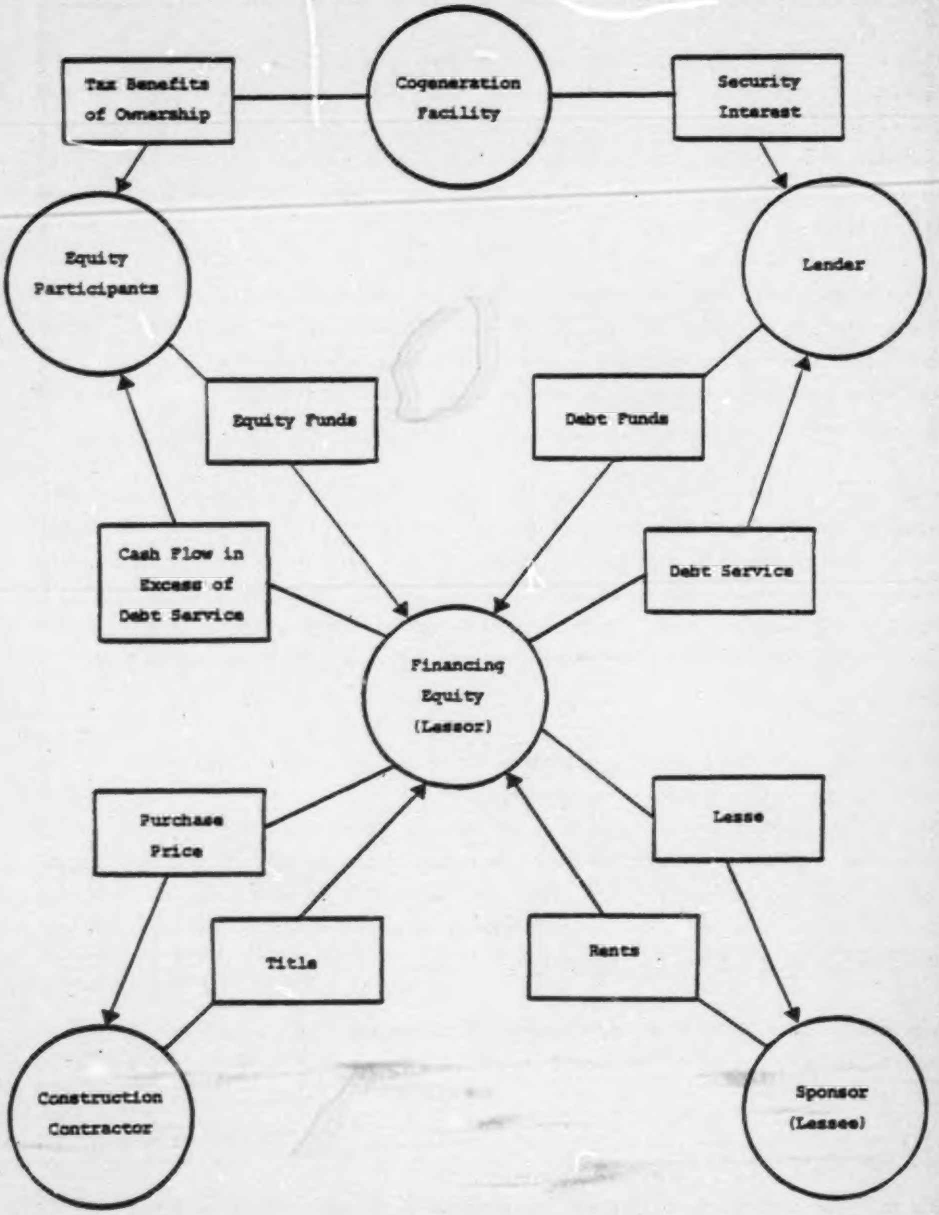
Tax Benefits of Ownership
Cogeneration Facility
Security Interest
Equity Participants
Lender
Equity Funds
Debt Funds
Cash Flow in Excess of Debt Service
Debt Service
Financing Equity (Lessor)
Purchase Price
Lease
Title
Rents
Construction Contractor
Sponsor (Lessee)

Figure 5-4. Leveraged Lease Financing for Cogeneration Facilities - Schematic Flow Diagram.

ADVANTAGES

- Ability to use tax credits, accelerated depreciation and tax loss carry forwards.
- Abundant capital available for financing energy projects to shelter income from taxes.
- Willingness to provide capital at lower cost.

DISADVANTAGES

- Risk of regulation being changed.
- Lack of technical expertise.
- Lessee does not own the residual value of the property at the end of the lease.

IMPLICATIONS FOR UTILITIES

Third party financing of cogeneration projects should be considered as a way to reduce effective capital costs and finance projects where other participants (industry, utility) cannot use the tax incentives. This method should become even more viable if energy tax credits are increased from 10 to 20%. The disadvantage to the utility is that the third party owns the property at the end of the term of the lease and that the assets do not become part of its rate base.

Figure 5-5. Advantages and Disadvantages of Sole Ownership of A Cogeneration Project by Third Parties.

commensurately reducing the possible returns. In addition a joint venture arrangement should reduce the "moral risk" of a project where two or more participants must cooperate: if all participants have a stake in the operation, they will have an incentive to do their part. This is particularly appropriate in the case of cogeneration, where cooperation between the industrial user(s) of the thermal energy and the utility purchaser of the electricity is essential.

Types of Joint Ventures

The term joint venture refers to financing a specific contractual relationship or undertaking among the two or more participants in a project. The legal relationship among the participants may take the form of a partnership, a jointly owned corporation, or an unincorporated association. The partnership structure offers great flexibility for joint venture arrangement between utilities and industrial cogenerators. The utility may, in fact, be able to contribute more than 50% of the equity to the partnership and/or receive more than 50% of the cash flow, and still qualify under PURPA as long as the assets are divided equally upon liquidation of the partnership.* A hypothetical partnership agreement could be structured as follows:

- Utility puts up 75% of equity and industry 25%.
- Utility gets 75% of the profit and losses and cash flow until the difference in their initial equity contribution is paid back. Thereafter, profits/losses and cash flow are split equally.
- If or when the partnership is terminated/liquidated, the utility and industry agree to split the value equally.

A joint venture arrangement should be regarded as an opportunity to achieve business and financing objectives which otherwise might not be attainable. A project too large to be undertaken by a single company may be accomplished by several through a joint venture. Also, certain credit supports or government guarantees may be available through a joint venture but not to each participant on an individual basis.

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*Opinion provided by FERC personnel based on informal review of hypothetical examples. These opinions do not carry assurance that an actual project structured along similar lines may not be treated differently.

Advantages of Joint Ventures

In some instances, the joint venture may be able to borrow the funds necessary to finance the project directly on its own credit. In other cases, the participants may prefer to supply the necessary credit indirectly through several or joint and several undertakings. In either case, lenders will consider the scope and purpose of the project in making credit decisions. For example, a joint venture consisting of a mixture of strong and weak credits may be able to borrow funds at a rate commensurate with the credit ranking of the stronger participants.

Another advantage of a joint venture arrangement is the possibility of obtaining off-balance sheet treatment which otherwise would not have been available. Generally, the obligations of a joint venture do not appear on the balance sheet of any participant having a voting interest of 50% or less. For federal income tax purposes, a joint venture is treated as a corporation and separate taxable entity if it is incorporated or if it possesses a majority of the corporate characteristics of a corporation.

Otherwise, it is generally treated as a partnership or an unincorporated association whose income, deductions and credits are allocated among and reported by the participants. Unincorporated joint ventures can provide great flexibility with respect to the allocation among the participants of tax deductions.

Special purpose joint ventures created to finance and own a project are treated as partnerships unless they have the characteristics of corporations for federal income tax purposes. If treated as a corporation, the tax benefits inherent in the ownership of the project can be used only by the joint venture and not flowed-through to the individual participants. This offers a natural opportunity to finance on a leveraged lease basis. This is because the joint venture is seldom able to generate sufficient taxable income, especially in the earlier years, to fully and effectively utilize the available tax benefits.

A schematic flow diagram of a joint venture financing is presented in Figure 5-6. A summary of the advantages and disadvantages of joint venture financing is presented in Figure 5-7.

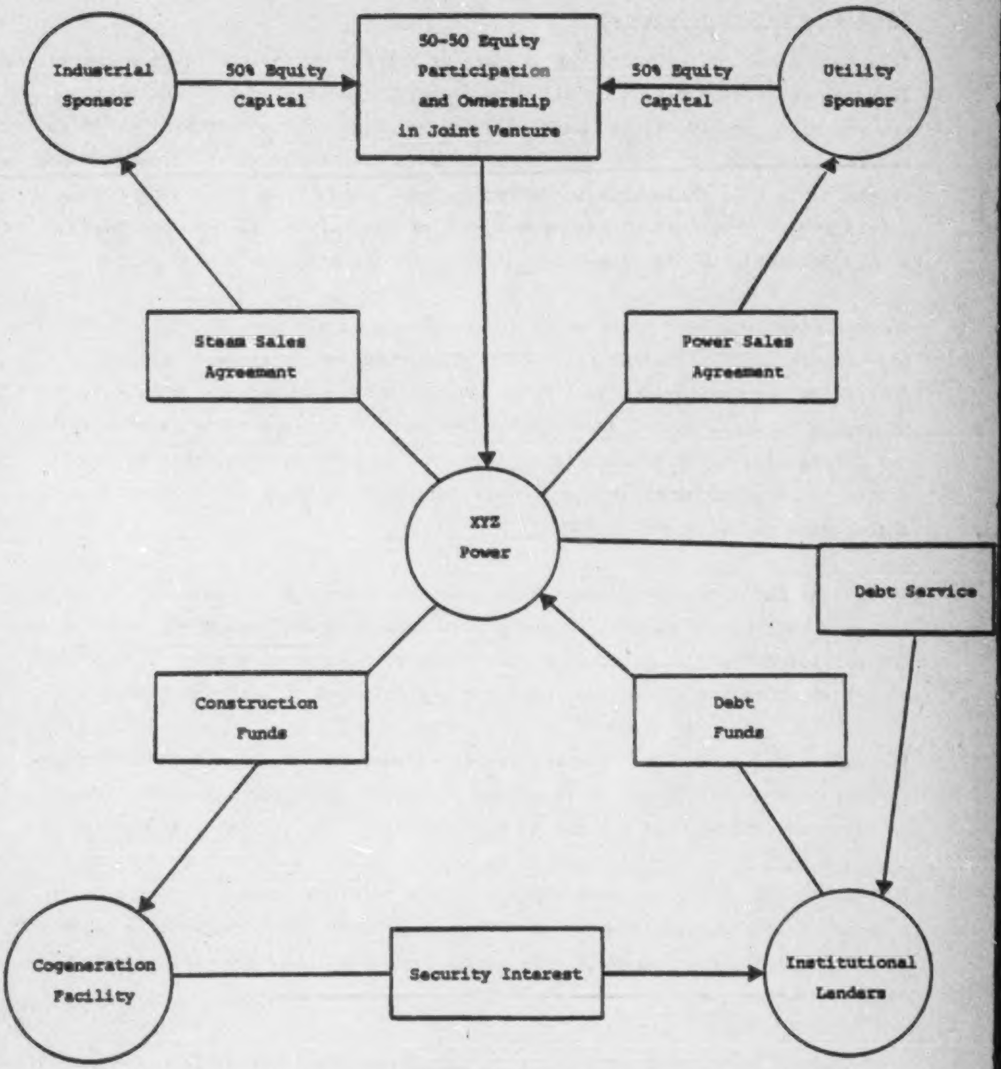
Industrial Sponsor
50% Equity Capital
50-50 Equity Participation and Ownership in Joint Venture
50% Equity Capital
Utility Sponsor
Steam Sales Agreement
Power Sales Agreement
XYZ Power
Debt Service
Construction Funds
Debt Funds
Cogeneration Facility
Security Interest
Institutional Lenders

Figure 5-6. Joint Venture Financing for Cogeneration Facilities - Schematic Flow Diagram.

ADVANTAGES

- May be able to use tax incentives more effectively than individual ownership.
- Provides additional sources of capital.
- May be arranged without impact on the balance sheets of the participants.

DISADVANTAGES

- Control over timing and use of the facility may not be optimal for all participants.
- Risk of regulations changing and the property being treated as a regulated utility operation.
- May impare the credit of the participants.

IMPLICATIONS FOR UTILITIES

Joint venture financing is the most likely method of financing cogeneration under the current PURPA ownership limits. Joint ventures can reduce the costs of capital and the capital requirements for participants when compared to the alternative of sole ownership. Joint ventures using partnerships allows great flexibility in structuring the financial arrangement between the participants.

Figure 5-7. Advantages and Disadvantages of Joint Venture Financing of a Cogeneration Project.

COGENERATION FINANCING STRUCTURES

Financing structure describes the arrangements used to secure capital, allocate risks and share benefits of the project that is being developed. The financing structures that are available for cogeneration project are undivided interest and project entity.

Undivided Interest Structure

The undivided interest structure may be used by a sole owner or a joint venture. The owner(s) of an undivided interest in a project contributes capital in proportion with his ownership and receives profits in the same proportion. Any funds borrowed to capitalize the project would be shown on the participant's balance sheet as would the assets of the project. If a wholly owned subsidiary owns an undivided interest in the project's assets, the parent would have to consolidate the subsidiary's accounting with its own as if it owned the undivided interest itself.

Project Entity Structure

Under the project entity approach, the cogeneration project would be established as a separate entity to own and operate the equipment. Project financing is the term used to describe the raising of capital to finance a project entity approach. The cogeneration project entity may be owned by a sole owner or by a joint venture. Each participant contributes capital and receives project benefits based on agreement with other participants and not necessarily in proportion to his ownership interest. Capital is secured by the project's assets and future cash flows. The debts of the project are not shown as debts on the participant's balance sheets. The project entity approach may affect the participant's cost of credit or ability to raise additional debt even though the project debt does not appear on the participant's balance sheet.

There are three basic variations on the project entity structure as shown in Figure 5-8 that include:

- Contract supported
- Separate equipment ownership
- Ownership changes with phases.

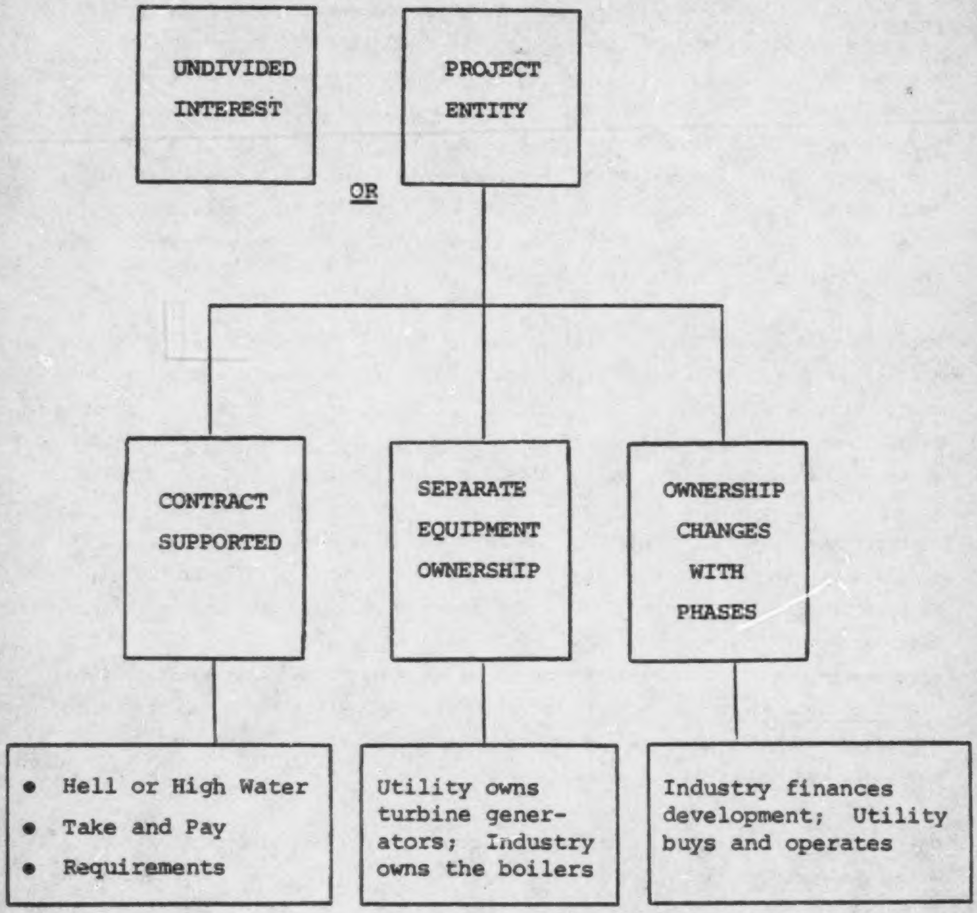
UNDIVIDED INTEREST
OR
PROJECT ENTITY
CONTRACT SUPPORTED
SEPARATE EQUIPMENT OWNERSHIP
OWNERSHIP CHANGES WITH PHASES
• Hell or High Water
• Take and Pay
• Requirements
Utility owns turbine generators; Industry owns the boilers
Industry finances development; Utility buys and operates

Figure 5-8. Cogeneration Financing Structures.*

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*These structures can be used by either a sole owner or a joint venture. These structures can either buy or lease the assets.

Contract-Supported Project Financing. Contract-supported project financing is the most common form of project financing and is really a form of credit support by the sponsors of a project. A cogeneration project is a much better risk from a lender's point of view if it has long-term contracts for the purchase of its outputs, namely, the steam and electricity. The sponsors can enter into such contracts and then assign them to the lenders. The contracts become a form of collateral, which reduce the risk, and therefore reduces the financing costs. Depending on how firm the contracts are, the owners may or may not have to show the obligations on their balance sheets.

The strongest type of contract to use as the basis for project financing is one that provides for payments to be made by the user of steam or electricity on an unconditional, full responsibility basis. Such contracts are commonly referred to as "hell-or-high water" obligations. In regulated industries, the term refers to an authorization to set prices on an "all events" basis.

Whatever the name, the requirement is the same: the user commits to pay for the cogeneration plant output, whether or not it is delivered or deliverable. The payment would be in an amount sufficient to cover periodic debt service requirements and operating expenses. Because of its similarity to an obligation to pay debt service, full responsibility contracts may have to be capitalized in the user's balance sheet. This contract may also affect the owner's use of asset depreciation, energy tax credits and investment tax credits since the risks of ownership are passed to the buyer.

One subset or the "hell-or-high water" contract is the requirements contract. A requirements contract obligates the buyer to buy all its steam or electric needs from the project at a calculated rate. Requirements contracts are rarely suitable for cogeneration project financing, since the lender must evaluate and bear the risk of a decline in the user's long term demand.

Other, less rigid contracts have also been used as the cornerstone of project financing. "Take-or-pay" contracts, in which the user agrees to pay when and if the steam or electricity is delivered, even if not taken, are common. This form of contact is becoming more readily accepted as the basis for a project financing, provided that no new or unproven technologies are involved and the sponsor or operator of the project is recognized as being expert in the production process.

"Take-and-pay" contracts are also used to finance projects by defining the terms of sale. This contract obligates the buyer to pay a fixed negotiated rate for its purchases but does not obligate it to buy. The least rigid form of contract that may exist in a cogeneration project is a customer agreement or scheduled or published rates.

A schematic flow chart which describes a simple contract-supported project financing for a cogeneration project is presented in Figure 5-9.

Different Methods for Different Equipment. Another possible means of combining various project entity structures is to divide the equipment to be employed in the project into separate component groups and to adopt a different ownership option for each group. A primary reason for using this approach would be to avoid the regulation of industrial participants in a state which recaptures the earnings from cogeneration and sale of electric energy. A financing structure may be employed in which the specific assets associated with steam production, principally boilers, burners and condensers, would be owned by the industrial companies through a project entity, while the turbine generators and related electrical equipment would be owned by the utility on a sole ownership basis.

This approach not only may insulate industrial owners from public utility regulation and give the utility direct control over electric production, but also may help the utilities that have limited capital. The largest cost components of cogeneration equipment are the boilers and fuel handling equipment which would be financed by the industrial participants.

Different Methods for Different Phases of the Project. A third means of integrating various structural approaches into the organization of a single project is to adopt different methods for the developmental and operational phases of the project. This approach can help the utility participant finance the construction of a facility and solve the problem which industrial participants have in financing utility-type assets with an industrial-type capital structure.

The basis of this method is that the industrial firm(s) will bear the burden of construction financing with the utility assuming responsiblity for permanent financing following completion of construction. This specific approach could be implemented in a number of ways. One way would be to have industrial participants own the facility during the construction phase and fund construction from their

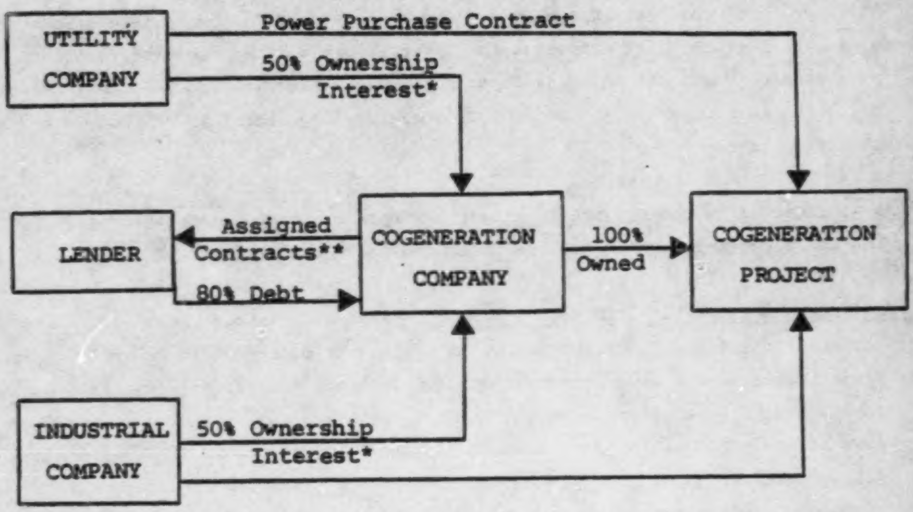
UTILITY COMPANY
Power Purchase Contract
50% Ownership Interest*
LENDER
Assigned Contracts**
80% Debt
COGENERATION COMPANY
100% Owned
COGENERATION PROJECT
INDUSTRIAL COMPANY
50% Ownership Interest*

Figure 5-9. Contract-Supported Financing of A Cogeneration Facility.

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*Equity contributions equal 10% of project costs.

**Debt is secured by contracts with the Cogeneration Company without recourse to the Utility Company or the Industrial Company.

own resources, including funds they may borrow in their own names. Upon completion, the facility would be sold to the utility which would thereafter operate it as sole owner and finance it with funds provided through its normal utility capital structure. The rates charged for the output of the project will reflect only the capital which the utility has employed from the commencement of its ownership. Compensation for the capital employed by the industrial firms during the construction period can either be included in the purchase price, or, in effect, earned by the industrial firms over the operating period through lower charges for output.

The disadvantage of this approach is that it does not relieve the utility from having to raise capital; it only postpones it. Secondly, the project once wholly owned by the utility would no longer be a qualifying facility and would earn only the utility's regulated rate of return.

Summary of Project Financing Structures

The most common project financing structure is contract supported. Other project financing structures include: separate equipment ownership and ownership that changes with project phases. The foregoing structures may properly be considered the basic building blocks of project financing. One of the keys to successful project financing, however, is the ability to arrange the structural components in such a manner as to meet the specific objectives and requirements of the participants. Each utility must evaluate both the theoretical and practical considerations involved in order to select from the various financing arrangements available for cogeneration projects. Except as a starting point, financial theory is not very helpful, focusing primarily on risk and how to minimize it or share it for a particular party. Financial theory assumes many things, including: competitive and efficient capital markets, complete knowledge among investors in those markets, equal costs of borrowing for all enterprises (at least for projects with equal degrees of risk), equal tax rates, and no special tax credits for particular classes of investors. To the extent that these assumptions do not hold true in the real world, the alternative financial structures previously discussed have particular advantages or disadvantages from the utility perspective.

The practical considerations involved in selecting a financing arrangement include: the ability of each participant to raise capital, the cost of the capital, alternative uses for the capital and the ability to maximize and utilize the tax benefits and other incentives available to the project. The utility and other potential participants must identify their financial capabilities and constraints to determine their proper roles in any cogeneration project. The structures identified above may be used to finance projects that could not be undertaken by any one participant or may produce greater project financial results by reducing capital costs through the best use of tax credits.

Senator HUMPHREY. Would electric utilities still want to go into cogeneration if they could not get full avoided cost?

Mr. MITCHELL. Yes, sir. What we are asking for is equivalent treatment on the electric output as that that any other party could receive, regardless of what that treatment is.

Senator HUMPHREY. You want what everyone else is getting. Now, how do you answer the arguments, or the implications that utilities are going to use this proposed authority to take advantage of the ratepayers?

Mr. MITCHELL. I would simply say that utilities are in a fishbowl. We are subject to complete regulatory scrutiny, both Federal and State, in almost every action we take. I think the regulatory authorities have adequate authority and opportunity to inspect all of our decisions, and to remedy any alleged anticompetitive effects.

I think also the threat of civil and criminal penalties for any unfair trade practices are such, in addition to the fish bowl that we are in, to preclude us from taking any unnecessary risk on unfair trade type of practices.

Senatory HUMPHREY. How do you respond to the suggestion that the utilities might manipulate circumstances to obtain the highest rate of cost for their own subsidiaries?

Mr. MITCHELL. Again, I would say once again that regulatory scrutiny is going to make sure that that does not occur. Let me make one other point, and that is my industry has always completely supported—again, another point developed by Mr. Chiles—that the regulatory methodology for avoiding cost payments should never be more than true avoided cost. In other words, no ratepayer subsidy of any cogenerator, regardless of ownership.

I think perhaps even more significant than that, my industry has been the one party in cogeneration who has consistently stood for something less than full avoided cost to a qualified facility, again with the prospect that the ratepayers will always receive some direct economic benefit from any cogenerator developed.

Senator HUMPHREY. How would this regulatory scrutiny work in an unregulated environment?

Mr. MITCHELL. The scrutiny is of the interphase between the unregulated utility and the utility itself and all the utility operations. I would presume it would come in two areas. One is a very transparent interphase in the sale of electric energy from the cogenerator to the utility. That is a very transparent, easily scrutinized arrangement between those two parties.

The second way that regulation would look at the utility's side of the equation is to see any cost transfers between the two parties, and that is well established in the regulatory precedent in the past.

Senator HUMPHREY. Another potential area of abuse is the delaying of negotiations for contracts on interconnection. How do you respond to the suggestion that utilities might resort to such tactics to their own advantage?

Mr. MITCHELL. Let me refer that to Mr. Schaeffer since I think the major part of the cogeneration interconnection in the United States today is probably in his area.

Mr. SCHAEFFER. Most of the people who are interested in selling H. L. & P. power right now are also major consumers of electricity. The petrochemical people and the refiners are all major consumers. They are also major cogenerators, so for us at least the very most significant aspect of the interconnection issue probably isn't too real. The biggest sellers or big users, they are interconnected with H. L. & P. In my own experience with H. L. & P. interconnection hasn't been an issue. I don't think it is particularly likely that H. L. & P. would delay negotiation with a bonafide cogenerator. I think the utility commission would have our head for it.

Any benefit we might derive would be easily offset by having the commission take regulatory remedies with the company for having implemented those delays in the first place.

Senator HUMPHREY. What do you think of Chairman Butler's suggestion that a quid pro quo situation be set up where interconnection is assured and expedited in exchange for utility participation in the benefits of section 210?

Mr. MITCHELL. Since the January 22 Circuit Court of Appeals decision my cogeneration issue group has taken up that question, perceiving it as one that has to be dealt with. We have not yet reached a conclusion on what the proper mechanism would be, but I would say personally that we do need to have a solution to that potential barrier that could be in place. And we will deal with that question.

Senator HUMPHREY. Are you speaking on behalf of EEI?

Mr. MITCHELL. I am saying on behalf of EEI we are studying the question to come up with a possible solution. In my own opinion it really does require some special treatment.

Senator HUMPHREY. Ms. Shanaman, did you want to offer a second opinion on any of these points raised so far?

Ms. SHANAMAN. I think perhaps the only thing I might additionally add is that I'm not sure, again, that the 50 percent limitation has been shown to be the only reason that we haven't gotten involved in cogeneration to a greater extent than what we have now.

I think we have to recognize that PURPA is still in its infancy. There have been many questions on the part of the utilities and industrial companies as to what kind of costs are going to be involved, what kind of maintenance responsibilities, what kind of regulatory treatment which I think are in the process of being answered.

It is those types of things which I think are more prevalent than the fact that the utilities haven't been able to have 100 percent ownership.

I think also we ought to recognize that there are inherent indirect benefits of decentralized industrial generation. One of those benefits was shown very clearly in Pennsylvania during the 1977-78 coal strike by the United Mine Workers where in the Pittsburgh area we were able to, I think up to an extent of 16 percent of the utility's peak demand, assisted in the stretch of the dwindling fuel stock of that utility to its other regulatory customers.

So I just don't want us to lose sight of that very important, the opposite side of the segment, and for what I think essentially 210 was developed for, and that was to encourage that industrial cogeneration.

Senator HUMPHREY. Thank you all very much. I appreciate it. Our next panel is comprised of Mr. William Nicholson who is representing the American Paper Institute; Mr. Robert L. Jamison representing the Council of Industrial Boiler Owners; Mr. Michael

J. Zimmer representing the Cogeneration Coalition, Inc.; and Mr. Peter Brown of Energy Law Institute.

I believe we will proceed in order on the list this morning. Mr. Nicholson, will you begin, please?

STATEMENT OF WILLIAM J. NICHOLSON, MANAGER, CORPORATE ENERGY SERVICE, POTLACH CORP., ACCOMPANIED BY RIGDON H. BOYKIN, CHADBOURNE, PARKE, WHITSIDE & WOLFF

Mr. **Nicholson**. Thank you. This morning I brought with me Mr. Rigdon Boykin. Mr. Chairman, I appreciate this opportunity to express the views of the American Paper Institute on the two bills pending before the Congress, S. 1885 and S. 1966.

We will be supplementing this testimony with written comments from one of our smaller member companies to give this subcommittee an actual example of some of the things mentioned in my testimony.

Senator **Humphrey**. What company is that?

Mr. **Nicholson**. Potsdam.[1]

My name is William J. Nicholson. I am employed by Potlach Corp. as manager of Corporate Energy Service. I am testifying on behalf of American Paper Institute, the National Trade Institution of the pulp, paper, and paperboard industry in the United States.

API consists of approximately 175 manufacturers that produce 90 percent of the Nation's pulp, paper and paperboard output. This industry is the third largest consumer of purchased electricity among manufacturing industries in the United States. Its annual bill for this form of energy is in excess of $1.8 billion.

In addition, the industry is today a major cogenerator of electricity. In fact, among industrial groups the U.S. pulp, paper, and paperboard industry is the Nation's leader in the cogeneration of electric power, accounting for close to 50 percent of the total cogeneration in the United States today, about 3,000 megawatts of capacity.

Aside from technological limitations which are few, full development of the cogeneration potential of the pulp and paper industry has historically been constrained by two factors, the economic attractiveness of investment in additional cogeneration capacity, and institutional relationships which are retarded rather than promoted private development of this technology. PURPA and the rules of the FERC have gone a long way toward removing these barriers.

Section 210 of PURPA has been successful. It has brought about an increased interest in cogeneration on the part of the American Paper Industry and on the part of industry at large.

It is still, however, an area of considerable uncertainty. Although PURPA dates back to 1978, there are today few States where industry has a sound idea of the revenue potential of cogeneration. This is not because of any inherent flaw in PURPA or the rules under PURPA, but because it takes time to convert policy into real economic terms upon which investment can be based.

Frankly, we would like to see the current alinement of policy and economics continue. We believe the present approach will work, and will utimately bring much of industry's cogeneration potential into the Nation's electrical grid.

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[1] See App. II.

We also believe the proposed legislation would be a major brake on the momentum that industrial cogeneration has gathered.

In this setting, S. 1885 would have an especially damaging effect upon nonutility development of power generation.

First of all, let me note that there is today no barrier preventing utilities from engaging in cogeneration and small power production. Utilities have done this in the past and will do so in the future. Nor is there any validity in the assertion that private industry will not exploit cogeneration and small power production because it lacks the requisite money and knowledge of power production technology.

As indicated, the paper industry has been generating power for years and is thoroughly familiar with the technologies. If the economics warrant expanded cogeneration, and there are no institutional barriers to putting privately generated electricity onto utility grids, industry has or will get the capital funds required.

PURPA and the rules thereunder wisely limit public utility participation in eligible generation activities to cases where a utility owns 50 percent or less of the relevant entity.

Congress recognized that there had been a history of utilities frustrating attempts of industry to generate power, its goal was to get private generation moving once more. There is nothing in PURPA which prevents a utility from engaging in cogeneration or small power production; rather the present ownership limitation reflects a reasonable conclusion that utilities need not be accorded the special incentives that are needed to get nonutilities to develop electric generation.

The technological advantages of cogeneration are fully available to utilities today, and are being used by them. In fact, some utilities have already built or are negotiating to build cogeneration facilities in conjunction with industrial companies, indicating that the present ownership limits are by no means an insuperable barrier. Moreover, as regulated industries, utilities are virtually guaranteed a fair return on their investment. There has been no showing that they require the incentives provided by PURPA.

S. 1885 also appears to permit exemption of utility-owned cogeneration from utility-type regulation. As purchasers of electric power from utilities, we question whether permitting or encouraging one part of the power generation of electric utilities to be unregulated will produce any public benefit.

Such an arrangement would obviously encourage utilities to shift qualifying productive assets into, or to acquire qualifying assets in unregulated divisions or subsidiaries that would be operated for the benefit of stockholders rather than to produce balanced benefits to ratepayers, the public and stockholders, that is commonly required by State utility regulation.

The utility would have every incentive to charge itself a higher rate for power sold by the subsidiary, which could well be passed on as higher rates for all consumers. Please note that I am not impugning utility managements, but surely, if only to respond to stockholder interests, they will have to make every reasonable effort to maximize the earnings to be derived from unregulated activities.

Moveover, there is a substantial danger that the enticement of unregulated profits from deregulated utility generation will encourage utilities to neglect the development of lower net cost base load generation capacity.

Removal of the 50-percent ownership limitation would create anticompetitive problems. By favoring its own deregulated operations, and by exploiting its energy monopoly, an aggressive utility could easily both corner the cogeneration market and substantially expand its electric energy monopoly.

The deregulation of utility cogeneration in conjunction with the de facto monopolies held by utilities will enable utilities to move into and dominate new areas. A utility would have every incentive to overpay its cogeneration arm, and to extract as well excessive rates for the cogenerated steam. Competition could be suppressed by the utility's careful manipulation of rates and conditions, which could effectively freeze out any potential cogenerator unable or unwilling to pay the costs of fighting the utility—made doubly difficult by the unregulated character of the utility's cogeneration operation.

It is to be recalled that the purpose of the cogeneration provisions of PURPA was to develop nonutility cogeneration as an addition to the Nation's basic electric utility system. The proposed legislation does not further this coal, but impedes it. Our reaction might be different if the legislation represented a comprehensive attempt to separate power generation from retail sales, and to deregulate the former. But it is nothing of the sort.

The measures proposed would merely distort and disrupt a program that gives every indication of being successful now that State commissions have acted, State rules are in place, and the potential benefit of private generations have become fairly widely known.

While I have detailed at some length our opposition to relaxing the 50-percent ownership limit, I do not want to leave the impression that there are no benefits of PURPA which can be extended to utilities.

For example, we certainly do not oppose extending to utilities the tax benefits presently applied to nonutility cogeneration facilities. There may well be other areas where accommodation is possible.

We are engaged in a continuing dialog with utilities and would hope there would be other areas where it would be appropriate to provide incentives to utilities.

However, to establish an across-the-board parity for all utility facilities will be counterproductive, and will frustrate rather than enhance the objectives of PURPA.

[The prepared statement of Mr. Nicholson follows:]

STATEMENT OF THE AMERICAN PAPER INSTITUTE TO THE SUBCOMMITTEE ON ENERGY REGULATION WITH RESPECT TO S. 1885 and S. 1966

I appreciate this opportunity to express to the Senate Subcommittee on Energy Regulation the views of the American Paper Institute ("API") on two bills pending before the Congress -- S. 1885 and S. 1966. We will be supplementing this testimony with the written comments of one of our smaller member companies to give this subcommittee an actual example of some of the things mentioned in my testimony.

My name is William J. Nicholson. I am employed by Potlatch Corporation as Manager Corporate Energy Service. My business address is Potlatch Corporation, P.O. Box 7864, San Francisco, California 94120. I have S.B. and S.M. degrees in chemical engineering from the Massachusetts Institute of Technology, a Ph.D. degree in chemical engineering with a minor in macroeconomics from Cornell University, and an M.B.A. from Pacific Lutheran University. I am a registered professional engineer in the State of Washington.

I am testifying today on behalf of the American Paper Institute, a national trade association of the pulp, paper and paperboard industry in the United States. API consists of approximately 175 manufacturers that produce 90% of the nation's pulp, paper and paperboard output. This industry is the third largest consumer of purchased electricity among manufacturing industries in the United States. Its annual bill for this form of energy is in excess of $1,800,000,000. In addition, the industry is today a major cogenerator of electricity. In fact, among industrial groups the U.S. pulp, paper and paperboard industry is the nation's leader in the cogeneration and self-generation of electric power, accounting for close to 50 percent of the total cogeneration in the United States today -- about 3,000 megawatts of capacity. In addition the pulp and paper industry tends to operate on a 24 hour basis for over 350-355 days per year.

While the existing level of cogeneration in the pulp and paper industry is clearly substantial, the industry's potential for even greater utilization of this technology awaits development. Before the passage of the Public Utility Regulatory Policies Act (PURPA), pulp and paper companies had little incentive to cogenerate power in excess of their own needs and in some cases had little economic incentive to generate power at all. In the light of institutional and economic constraints, it has been difficult to justify the necessary investment of capital and effort in modifying equipment and industrial processes to engage in more extensive electric generation operations. However, greatly expanded cogeneration output is technologically within the industry's reach and, with the implementation of PURPA, possible to attain. Thus API has a strong and abiding interest in the development of cogeneration and small power production.

Cogeneration in the paper industry usually consists of the production of steam at high temperature and pressure, which is first expanded through a steam turbine to generate electric power and then extracted or exhausted from the turbine at lower temperatures and pressures, to be used in the industrial process for such purposes as mechanical drives, pulping, drying, bleaching and space heating.

When the generation of electricity is considered in isolation, large public utility generating plants are more efficient than are industrial generating facilities, but overall the cogenerating plant is far more efficient because its sequential use of energy sharply reduces waste. A public utility converts approximately 35% of its energy Btu input into electric power at the plant bus bar. In a typical pulp and paper plant, over 80% conversion of available energy into useful energy-- electric power and process steam - is achieved. The potential savings of fossil fuels (often oil and gas) are compounded by the use of pulp mill residues, such as bark or spent liquors from the pulping process, as fuel. Today these biomass residue fuels constitute over 50% of the total energy consumed at U.S. pulp and paper mills.

Aside from technological limitations, which are few, full development of the cogeneration potential of the pulp and paper industry historically has been constrained by two factors: the economic attractiveness of investment in additional cogeneration capacity, and institutional relationships which have retarded rather than promoted private development of this technology.

As a practical matter, five requirements must be satisfied to attract substantial development of private generation. These requirements include:

1. Freedom from utility-type regulation in regard both to duties and responsibilities and to disclosure of private business records.
2. Assured interconnection to the utility grid.
3. Separation of the private generator's electricity generation from its electricity purchases. Purchases should be available at nondiscriminatory rates in relation to similarly situated non-generating utility customers.
4. The payment of avoided cost for power sold to utilities.
5. Wheeling at the private generator's option and expense so that he can take advantage of the highest avoided costs available on the grid when local avoided costs are not high enough to provide an adequate return on investment.

In contrast to the fixed return on investment guaranteed to utilities, the private generator takes a financial risk in supplying power to the grid on a commercial basis.

Establishment of full avoided cost rates and adoption of the foregoing policies, however, may reduce the private generator's risk to an acceptable margin so that investment and development will take place.

Not all of these factors would be directly affected by S. 1885 and S. 1966, but they are interrelated and clearly relevant to any proposal such as S. 1885 that would place utilities on the same footing as private generators with respect to PURPA.

Let me also note that there is today no barrier preventing utilities from engaging in cogeneration and small power production. Utilities have done this in the past and will do so in the future. Nor is there any validity in the assertion that private industry will not exploit cogeneration and small power production because it lacks the requisite money and knowledge of power production technology. As indicated, the paper industry has been generating power for years, and is thoroughly familiar with the technology. If the economics warrant expanded cogeneration, and there are no institutional barriers to putting privately generated electricity onto utility grids, industry has or will get the capital funds required.

Section 210 of PURPA Was Properly Designed to Encourage Private Generation and Has Provided a Needed Impetus for Private Generation

Section 210 of PURPA has been successful. It has brought about an increased interest in cogeneration on the part of the American paper industry and on the part of industry at large. In the past, for many reasons, it was difficult to get electric utilities to consider our industries potential for supplying them with power. Now, under Section 210 of PURPA and the rules promulgated thereunder, this has changed. Most important, and in contrast to the past, the increased economic incentives are causing industry to factor such potential opportunities into its planning, capital budgets, designs and construction.

It is still, however, an area of considerable uncertainty. Although PURPA dates back to 1978, there are today few states where industry has a sound idea of the revenue potential of cogeneration. This is not because of any inherent flaw in PURPA or the rules under PURPA, but because it takes time to convert policy into real economic terms upon which investment can be based.

Frankly, we would like to see the current alignment of policy and economics continue. We believe the present approach will work, and will ultimately bring much of industry's cogeneration potential into the nation's electrical grid. We also believe that the proposed legislation would be a major brake on the momentum that industrial cogeneration has gathered.

There can be no question but that the recent decision of the District of Columbia Circuit Court of Appeals in American Electric Power vs. Federal Energy Regulatory Commission, ____ F.2d _____, rehearing denied, _____ F.2d ____, has been an adverse development, if only because it adds further uncertainty to the economics of private generation, not to mention the institutional barriers it has recreated. (It is to be noted that the plaintiffs in the AEP case were utilities.) In the AEP decision the court sustained rules promulgated under PURPA by the Federal Energy Regulatory Commission ("FERC") relating to simultaneous purchases and sales and with respect to fuel use, but it remanded the FERC rule requiring the payment of full avoided cost for privately generated power and invalidated the FERC rule requiring interconnection. I would note that in the denial of a rehearing en banc the court was sharply divided on the validity of the rules. The decision was 3 to 2 with the two dissenting judges issuing an opinion that the rules were valid and that the panel used the wrong standard of review.

While this setback to private generation may (or may not) be only temporary, it emphasizes the need of potential generators for an economic and institutional environment that will be reasonably durable and certain.

In this setting, S. 1885 would have an especially damaging effect. It would put utilities into direct competition with the rest of industry for the development of cogeneration and small power production.

PURPA and the rules thereunder wisely limit public utility participation in eligible generation activities to cases where a utility owns 50 percent or less of the relevant entity. Congress recognized that there had been a history of utilities frustrating attempts of industry to generate power, its goal was to get private generation moving once more. Note again, that nothing in PURPA prevents a utility from engaging in cogeneration or small power production -- rather the present ownership limitation reflects a reasonable conclusion that utilities need not be accorded the special incentives that are needed to get non-utilities to develop electric generation. The technological advantages of cogeneration are fully available to utilities today, and are being used by them. In fact, some utilities have already built or are negotiating to build cogeneration facilities in conjunction with industrial companies, indicating that the present ownership limits are by no means an insuperable barrier.

Moreover, as regulated industries, utilities are virtually guaranteed a fair return on their investment. There has been no showing that they require the incentives provided by PURPA.

Making PURPA applicable to utilities as well as non-utilities will encourage utilities to engage in even more foot-dragging and delay. Under the existing statute their response to private generation has, with a few exceptions, been one of delay or refusal. This would be exacerbated by S. 1885. With utilities competing for generation opportunities, non-utilities and developers will be seriously handicapped. Negotiations for contracts will be stalled, with the utility either no longer feeling the full mandate of the PURPA rules, or seeking to apply them for the utility's benefit only. The utility will be further motivated to delay while it seeks ownership of the otherwise private facility. In most cases industrial cogeneration will be discouraged because few industrial companies will want the exposure to regulation that they perceive as attending any joint venture with a utility. It is difficult enough for an industrial company to decide to commit its own resources to cogeneration. Introducing an outsider complicates the picture. Yet the utility, especially if a cogeneration venture will be outside of ordinary rate regulation, will have every incentive to hold out for ownership rather than getting on with the business of simply purchasing power from the cogenerators, as is required by PURPA.

It must be stressed that industries such as the pulp and paper industry, in contrast to utilities, are unregulated, have no returns protected by rate regulation, and are completely at risk in their cogeneration ventures. They enter into a venture hoping it will be profitable, but it can also turn into a loss. The risks they perceive will be considerably greater if utilities are permitted to compete with them with respect to cogeneration and small power production.

S.1885 also appears to permit exemption of utility-owned cogeneration from utility-type regulation. As purchasers of electric power from utilities, we question whether permitting or encouraging the power generation of electric utilities to be unregulated will produce any public benefit.

Such an arrangement would obviously encourage utilities to shift qualifying productive assets into, or to acquire qualifying assets in, unregulated divisions or subsidiaries that would be operated for the benefit of stockholders rather than to produce balanced benefits to rate payers, the public and stockholders, that is commonly required by state utility regulation. The utility would have every incentive to charge itself a higher rate for power sold by the subsidiary, which could well be passed on as higher rates for all consumers. Please note that I am not impugning utility managements -- but surely, if only to respond to stockholder interests, they will have to make every reasonable effort to maximize the earnings to be derived from unregulated activities.

It also appears that eliminating the 50% restriction could lead to a form of "cream skimming" that would be highly detrimental to the ongoing cogeneration effort and our effort to make use of heat that would otherwise be wasted.

If a utility is unenthusiastic about cogeneration, or simply sees a chance to divert their generation of power into an unregulated pocket, it would be able to preempt the market by building a number of unregulated cogeneration or "small" power production facilities. The higher avoided cost payments* would go to itself, and industrial cogenerators, if still interested, will be left with lower payments for their cogenerated power. Moreover, there is a substantial danger that the enticement of unregulated profits from deregulated utility generation will encourage utilities to neglect the development of lower net cost base load generation capacity.

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* In most cases, avoided costs will be higher for the first qualifying facilities to go on line, and progressively lower as more cogenerators or small power producers are paid avoided costs.

We do not believe this scenario is by any means unlikely. Peaking turbines are often relatively small generating units; one or two utility owned cogeneration or small power production units could easily displace the peaking turbines on many systems. Certainly in most cases the utility would have enough control over industrial cogeneration negotiations to delay them until after it firms up its plans for its own cogeneration facilities.

There is also reason for concern that opening this new area for utility activity will divert the focus of utility managements focus from the major problems facing most utilities today. This is a time of profound change and challenge for the utility industry. Enabling utilities to compete with other industries and with other utilities for cogeneration operations could encourage utility management to turn its back on more serious problems. However, the competition could be intense, and might demand, irrespective of management's better intentions, that the utility focus on cogeneration rather than its basic job, that of generating and delivering electric power at the lowest possible cost to its customers.

Anticompetitive Problems

Removal of the 50 percent ownership limitation would create anticompetitive problems. By favoring its own deregulated operations, and by exploiting its energy monopoly, an aggressive utility could easily both corner the cogeneration market and substantially expand its electric energy monopoly.

The obstacles faced by potential cogenerators in the past are well known. High rates for back-up and supplementary power, expensive interconnections, safety requirements and the like all combined to suppress cogeneration. PURPA has helped change that. Permitting utilities to enter the cogeneration arena could well create the same problems all over again. Notwithstanding the pressure of PURPA, it will be most difficult to prevent a utility from favoring its own branch or subsidiary in purchasing power, as by more generous allowances for interconnection, or capacity cost allowances - almost any aspect of what would otherwise be an arm's length transaction. All but the most aggressive industrial cogenerators would probably defer to the utility in such a case. The smaller cogenerators do not have the expertise and resources to contest many such issues with a utility. The utility's focus in promoting its own cogeneration will likely relegate private generators to last place. The utility will also have an incentive to manipulate avoided cost calculations and/or the timing of capacity additions so as to pay its own cogeneration units higher rates, leaving lower avoided costs to be paid to others.

Deregulation of utility cogeneration and "small" power production could also create another anti-competitive and regulatory problem. Because this utility generation would be exempt from a state commission's jurisdiction, the commission would be under very real pressure to force the level of "avoided cost" down to indefensibly low levels. Interest in preserving its own jurisdiction and pressure from rate payers would assure this. The result of depressed rates for cogenerated power would be not only to discourage utility cogeneration and small power production, but equally or even more to suppress the development of these processes by industry.

The deregulation of utility cogeneration in conjunction with the de facto monopolies held by utilities will enable utilities to move into and dominate new areas. A utility would have every incentive to overpay its cogenerating arm, and to extract as well excessive rates for the cogenerated steam. Competition would be suppressed by the utility's careful manipulation of rates and conditions, which could effectively freeze out any potential cogenerator unable or unwilling to pay the costs of fighting the utility -- made doubly difficult by the unregulated character of the utility's cogeneration operation.

Apart from these specific examples, there is also the lesson of experience that tells us that utilities are prone to expand their monopoly status. Hence, _e.g._, the Public Utility Holding Company Act.

It is to be recalled that the purpose of the cogeneration provisions of PURPA was to develop _non-utility cogeneration_ as an addition to the nation's basic electric utility system. The proposed legislation does not further this goal, but impedes it. Our reaction might be different if the legislation represented a comprehensive attempt to separate power generation from retail sales, and to deregulate the former. But it is nothing of the sort. The measures proposed would merely distort and disrupt a program that gives every indication of being successful now that state commissions have acted, state rules are in place and the potential benefit of private generations have become fairly widely known.

One closing note. As you can see, there are plenty of problems associated with promoting cogeneration and small power production. While I have detailed at some length our opposition to relaxing the 50% ownership limit, I do not want to leave the impression that there are no benefits of PURPA which can be extended to utilities. For example, we certainly do not oppose extending to utilities the tax benefits presently applied to non-utility cogeneration facilities. There may well be other areas where accomodation is possible. We are engaged in a continuing dialogue with utilities and would hope there would be other areas where it would be appropriate to provide incentives to utilities. However, to establish an across-the-board parity for all utility facilities will be counterproductive, and will frustrate rather than enhance the objectives of PURPA.

Thank you.

Senator HUMPHREY. Thank you. Mr. Jamison?

STATEMENT OF ROBERT L. JAMISON, MANAGER, EXTERNAL ENERGY AFFAIRS, WEYERHAEUSER CO., ON BEHALF OF THE COUNCIL OF INDUSTRIAL BOILER OWNERS, ACCOMPANIED BY EARLE H. O'DONNELL, ATTORNEY

Mr. JAMISON. I am Bob Jamison, manager of external energy affairs of Weyerhaeuser Co.. I'll be speaking on behalf of the Council of Industrial Boiler Owners. This is a broad based association of industrial boiler operators and related equipment manufacturers.

I have with me our legal counsel, Earle O'Donnell on my left. Also present in the room is Bill Marks, who is president of the Boiler Council.

Our testimony will focus on the cogeneration aspects of S. 1885. Council of Industrial Boiler Owners opposes the elimination of the ownership limitation at this time because of three reasons.

First, removing the 50 percent ownership requirement would encourage utilities to supply power free from the regulatory process that protect consumers from excessive rate charges.

Second, Congress consciously and specifically decided to give encouragement to nonutility entities whose primary business is other than electricity production. Utilities already have incentives.

Third, Federal incentives to enhance utility financial help seem unneeded because their overall financial help is currently improving. Problems confronting an individual utility may best be handled at the State level.

Taking these one at a time in more detail, first the ownership limitation. Nothing in PURPA section 210 currently prevents electric utilities from owning or operating a cogeneration facility. The ownership limitation is specifically directed at electric utilities that have a large portion of their business presently subject to State and Federal regulation.

Our fear is that these utilities would find it profitable to put their new investment capital into unregulated facilities while neglecting their regulated baseload facilities to the detriment of existing ratepayers. Indeed, good stewardship of their stockholders would require this. Leaving the ownership limitation would take us back to pre-PURPA and the problems PURPA was designed to overcome, and PURPA has helped overcome those.

Industry is also concerned the repeal of the ownership limitation will diminish the effectiveness of present State regulation on utility rates. As electric utility companies begin to operate unregulated generation facilities and purchase increasing amounts of electricity from their unregulated subsidiaries, a small portion of utility operations will be subject to regulatory review, resulting in a lower level of consumer protection.

The second reason is encouragement from nonutility cogenerators. Utilities already have both the obligation and the incentive to develop cost-effective generation resources, including cogeneration. Because of the legal monopoly granted to utilities, the FERC and State public utility commissions were established to overview this position and protect the interest of consumers.

Industry and other nonutility entities, on the other hand, have a primary function other than electricity generation. PURPA recognized the need to encourage these nonutility entities to risk some of their capital in electricity generating resources.

In today's scarce capital climate, this would help reduce utility financial burdens. The third reason is financial health of the electric utility industry. Financial health of the electric utility industry has recently begun to improve markedly in four ways. First, aggregate rate increases have increased to about $8 billion more as reported in 1981 earnings, and return on investment or equity has increased from something like 11.4 to 12.6 percent. Last year there were 97 increases in dividends versus 78 from the year before.

Third, collection of rate increases filed before the FERC has been much more rapid; and, four, stock prices are higher due to incentives from the Economic Recovery Tax Act of 1980. These events raise serious questions about the need for or wisdom of additional Federal programs to financially benefit utilities at this time. Some individual utilities may be facing financial problems, but these can and should be dealt with at the State level.

In summary, the Council of Industrial Boiler Owners believes that cogeneration can be effectively developed by nonutility entities as intended by PURPA. Incentives provided by section 210 are needed to encourage the development of cogeneration by those utilities or those entities whose primary interest is not electricity generation. Utilities already have an obligation and incentive to develop cost-effective generation resources, including cogeneration.

The Council of Industrial Boiler Owners believes that electric utilities should support the development of cogeneration by non-utility entities, and where appropriate, develop cogeneration resources in their own regulated environment.

We thank you for this opportunity to express our views and would enjoy continuing to cooperate with your committee.

[The prepared statement of Mr. Jamison follows:]

cibo
COUNCIL OF INDUSTRIAL BOILER OWNERS

Testimony of Robert L. Jamison
on behalf of the
Council of Industrial Boiler Owners
before the
Subcommittee on Energy Regulation
of the
Committee on Energy and Natural Resources
United States Senate

April 19, 1982

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My name is Robert L. Jamison. I am Manager, External Energy Affairs of Weyerhaeuser Company. I am testifying today on behalf of the Council of Industrial Boiler Owners.

INTRODUCTION

The Council of Industrial Boiler Owners (CIBO) is a broad-based association of industrial (non-utility) boiler operators and related equipment manufacturers. CIBO was formed in 1978 to encourage the maximum exchange of relevant information among its members and between industry and government to assure that public policy in the fuel utilization and environmental areas is realistic and supportive of individual and national economic integrity. Its members' interests cover sixteen major industry groups, including chemicals, food, primary metals, textiles, lumber, paper, petroleum and machinery. While many of the points made in this testimony may also be applicable to small power producers, CIBO will focus in this testimony on the major issue of concern to its members -- the impact of this proposed legislation on cogenerators.

By amending sections 3(17)(c) and 3(18)(b) of the Federal Power Act, S.1885 would eliminate the ownership limitation presently contained as part of the definitions of a "Qualifying small power production facility" and a "Qualifying cogeneration facility". The principal purposes which have been cited for this proposal are that it will encourage cogeneration and enhance the financial health of the utility industry. Because CIBO believes that repeal of the ownership limitation would not accomplish either of the purposes noted above; and, in fact, may impede development of cogeneration, CIBO opposes elimination of the ownership limitation at this time.

GENERAL CONSIDERATIONS

Before discussing in detail the impacts of this proposed legislation, it is important to understand the operation and purposes of the Public Utility Regulatory Policies Act (PURPA) as originally enacted.

- Congress passed PURPA in 1978 to create incentives for investment in cogeneration and small power production facilities. Section 210 of PURPA amended the Federal Power Act to include the definitions of a "qualifying cogeneration facility" and a "qualifying small power production facility". A facility that falls within these statutory definitions is entitled to the benefits created by PURPA, including exemption from public utility regulation and beneficial rate treatment.

- Recognizing the special problems faced by non-utility cogenerators under federal and state law, such as concerns over possible regulation as public utilities and the unwillingness of many utilities to buy cogenerated power or provide standby power at a reasonable price, the Congress specifically granted incentives to encourage cogeneration by non-utilities under Sections 201 and 210 of PURPA. Many of the incentives provided by PURPA, such as exemption from public utility regulation and provisions requiring utilities to buy power from a cogenerator, do not apply or are much less important to an already regulated utility.

- Nothing in the existing PURPA law prevents electric utilities from owning or operating a cogeneration facility and, in fact, PURPA and the FERC regulations implementing PURPA permit electric utilities to receive the rate and other benefits of PURPA where the utility owns up to a 50% interest in a cogeneration facility. It is important to note at the outset that the ownership limitation does not prohibit an electric utility company from owning even a 100% interest in a cogeneration or small power production facility. Rather, the limitation only bars an electric utility from attaining the "qualifying facility" status and the various Federal benefits flowing from it, where it owns a majority interest in the unit. Utilities generally can construct and operate such units under Federal laws (and should, if economically feasible), and receive whatever rates are permitted under state law. Equally important, the present ownership limitations do permit, and encourage, electric utility companies to negotiate joint ventures with firms that are not electric utilities. Even with the present limitations, an electric utility can still own up to a 50% interest in such joint ventures and receive the rate and other benefits under PURPA. Hence, utilities are generally free under Federal law to build and own cogeneration units and, in some cases, can obtain the benefits provided by PURPA for these units.

THE OWNERSHIP LIMITATION IS LOGICAL AND APPROPRIATE

° The rationale for the ownership limitation is simple. Citing Congressional hearings on PURPA, the FERC explained that these restrictions were "...based on a concern that [electric utilities] would divert scarce capital resources or convert existing jurisdictional facilities into unregulated facilities". (45 F.R. 66788). The ownership limitation preserves state regulation of electric utilities which already have a large portion of their business presently subject to state and federal regulation. Congress feared that these companies, if exempted from federal and state regulation by PURPA, would find it profitable to put new investment in unregulated facilities, while neglecting their regulated facilities, to the detriment of existing ratepayers. In contrast, companies that are primarily not engaged in the sale of power at wholesale or retail have little opportunity or incentive to divert resources to unregulated enterprises and are, therefore, exempt from the ownership limitation. */ Similarly, companies that generate all of their electricity for their own use from unregulated cogeneration or small power production facilities are exempted from the 50% ownership rule since these companies have no regulated facilities to neglect. The rationale behind these regulations, thus, is that the potential for abuse is greatest and, therefore, the regulations most strict with utility companies that are in the business of selling power to ratepayers and have a large portion of their business presently subject to regulation.

° Congress' fear of possible abuse in these situations, absent the ownership limitation, is well-placed. If the ownership limitation is removed, electric utility companies may give priority to unregulated generation facilities in their future investments, instead of investing additional capital in regulated facilities that might provide a greater benefit to existing ratepayers. In addition, as electric utilities start investing in unregulated facilities and as bifucrated electric systems arise, conflicts between the utility and its customers could occur. Customers requesting new or additional service

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*/ To implement this exemption, the FERC amended its regulations to provide that companies that have obtained an exemption from the PUHCA under Sections 2(a)(3), 3(a)(3), or 3(a)(5) are not subject to the ownership limitation. Those sections exempt companies that are primarily engaged in non-public utility businesses or companies that derive no material part of their income from a public utility company.

could be faced with a utility unwilling or unable to serve the additional load through their regulated generation facilities.

- As a further concern, if utilities place substantial investment in cogeneration facilities, the present price of electricity within each utility system could be significantly altered. As electric utilities start operating bifurcated systems, their investment and sales decisions will be rearranged to maximize revenues. The effect this could have on future rates is speculative; but to the extent that rates change significantly, prior investment decisions made by industry based on projections of future electric rates could be adversely affected.

- Additionally, electric utilities are franchized monopolies which have, because of their special legal status, a variety of obligations to their ratepayers. In general, these include the obligation to provide service to all those within their service territory at the cost of providing that service plus a reasonable rate of return. The proposed legislation would fundamentally alter this relationship. Because utilities will readily agree to favorable sales terms with their subsidiaries, utilities, through these subsidiaries, would receive full avoided costs for sales of power and, typically, an unregulated price for sale of thermal energy. Such an arrangement would preclude the utility's ratepayers from sharing in any of the benefits of cogeneration. Rather, the benefits will be divided between the affiliate - the cogeneration facility owner

- and the purchaser of the unregulated thermal output from the cogeneration facility. If utilities and their affiliates are to enjoy the advantage of a monopoly in the electricity marketplace, then they must also share with their customers - the ratepayers - the rate advantages of cogeneration. The electric monopoly was not established to benefit the electric utility, but rather the ratepayer.

In contrast, utilities may be, and generally have been, reluctant to pay full avoided costs to non-affiliates. Indeed, many cogeneration contracts negotiated to date provide for payment of less than full avoided costs to cogenerators. By providing an incentive to utilities to pay the highest rate possible to affiliated cogenerators, this legislation could lead both to higher rates for ratepayers and discriminate against industrial cogenerators.

- CIBO is also concerned that the repeal of the ownership limitation will diminish the effectiveness of present state regulation of utility rates. As electric utility companies begin to operate unregulated generation facilities and purchase increasing amounts of electricity from their unregulated subsidiaries, a smaller portion of utility operations will be subject to regulatory review with a reduction in consumer protection.

IMPACT ON COGENERATION

Repeal of the ownership limitation would also put utility companies in competition with industrial companies for the sale of cogenerated power to that utility. Unless overturned by the Supreme Court, the recent court decision in AEP, et al. v. FERC, which was decided after this legislation was introduced, will enable utilities wishing to avoid purchasing cogenerated power from non-affiliates to compel many industrial cogenerators to go through a prolonged FERC hearing prior to interconnection with the utility. Utility companies preferring to purchase from their own unregulated cogeneration facilities could use this hearing process to delay the purchase of power from industrial cogenerators. Similarly, the AEP decision overturned the FERC regulations providing that cogenerators can receive full avoided costs for sales of power. If these regulations are ultimately overturned, FERC will be required to initiate a new rulemaking to consider whether to establish a new rate standard. In the interim, a utility could frustrate the purposes of PURPA by refusing to agree to a reasonable rate for purchases of cogenerated power from non-affiliates.

- As the above makes clear, PURPA and the FERC regulations leave many critical issues to the negotiation process. In addition to the items noted above, these issues include such basic matters as the length of the contract term and whether to include some minimum payment provision in the contract to preserve cash-flow to the cogenerator. Satisfactory resolution of these issues may be critical to obtaining financing for a planned unit. Utility subsidiaries might well find it easier than non-affiliates to negotiate favorable terms on these important issues with their parent. The utility might, for instance, be willing to pay preferential avoided costs, establish favorable minimum bill provisions or agree to long-term sales contracts for a subsidiary to assist the subsidiary in obtaining financing for the project.

- Furthermore, industry requires a climate of stability in regulation in order to encourage it to risk the investment required to substantially expand cogeneration. Expansion of PURPA to include utilities at the same time that serious legal doubts have been raised about major elements of the FERC regulations due to the AEP v. FERC decision can only raise additional uncertainty and further delay investment of scarce capital in such units.

- Achievement of the goals of PURPA has been handicapped primarily due to utility unwillingness to offer an appropriate avoided cost. Other factors are slow implementation by the states and the decision in AEP v. FERC. While the economic incentives in the Act have provided some encouragement for industry to engage in cogeneration, this progress has been slowed or even stalled in some cases by difficulty in negotiating contracts based on acceptable avoided cost rates. Furthermore, PURPA rules have not yet been implemented in many of the 50 states so the full effect of the law cannot yet be assessed. CIBO believes that before Congress considers a major extension of the Act as would occur under S.1885, it should allow the existing statutes to be implemented.

THE FINANCIAL DIFFICULTIES BEING EXPERIENCED BY SOME ELECTRIC UTILITIES WILL NOT BE REMEDIED BY REMOVING THE OWNERSHIP LIMITATION.

The financial health of major portions of the electric utility industry has recently begun to improve. Recent reports reveal that: (1) states and the FERC approved eight billion dollars in aggregate rate increases in 1981 over 1980 rates; and (2) many utilities announced increases in dividends in 1981. Furthermore, FERC has adopted procedures to permit more rapid collection of rate increases and the states issued many more orders approving rate increases in 1981 as compared to 1980. Notwithstanding the improved trend for the utility industry as a whole, obviously, the financial condition of individual electric utilities is anything but uniform, and, in fact, varies widely from region-to-region. Among the reasons for these variations are 1) differences in the base load fuel used by individual utility systems; and 2) different near term capital requirements. Certain coal and nuclear base-load systems are, in fact, in good financial condition, while some oil and gas fueled based-load systems face enormous future capital requirements and are in a much poorer financial position.

Therefore, CIBO believes that federal legislation applicable to the whole industry is not an appropriate solution to a problem which may primarily confront only a relatively few systems. If some state regulatory bodies are not properly balancing the interests of consumers and stockholders, efforts should be directed at improving regulation at the state level, not at the federal level.

CONCLUSION

CIBO believes that repeal of the ownership limitation is inappropriate until PURPA as originally enacted has been fully implemented and time allowed to consider its effects fully. CIBO believes that elimination of the ownership limitation at this time could endanger utility service to ratepayers. In addition, it would impede the development of new cogeneration facilities. Finally, it believes that the rate problems confronting individual utilities in certain states should be corrected at the state level, not through federal legislation applicable to the entire electric utility industry.

Senator **Humphrey**. Thank you, Mr. Jamison.

Mr. Zimmer.

STATEMENT OF MICHAEL J. ZIMMER, WASHINGTON COUNSEL, COGENERATION COALITION, INC.

Mr. **Zimmer**. My name is Michael Zimmer. I am here this morning to represent the viewpoints of the Cogeneration Coalition, Inc. I think a concise statement of our summary, Mr. Chairman, is the summary contained at the bottom of page 4 and over to the top of page 5, wherein we do express the viewpoint that action at this time on legislation such as S. 1885 is premature at this time for the reasons enumerated therein.

More importantly, to get at what is really the issue here, first of all, I think we must examine whether or not PURPA itself is perceived as effective in terms of promoting cogeneration development. I think the answer to that question is an important condition in reaching to the next question that is before us today, and that is whether or not legislation such as S. 1885 is, in fact, necessary and desirable.

I would submit that the record developed thus far before this committee today and the record developed on the House side on this issue last year does not specifically indicate that the removal of the ownership limitation, or that the ownership limitation itself, is the root cause, or the cause of a failure in terms of PURPA and the development of cogeneration development.

In that regard, we then are really in a position of losing sight of what are really the critical key PURPA issues today, and that is the question of rates associated with these transactions. Second, the interconnection policies associated with hooking up these facilities to the electric utility and, third, the issue of the conducting of good-faith negotiations to bring about the implementation of the goals and objectives of PURPA as enacted by this Congress, as implemented by the FERC and ultimately the State commission.

Furthermore, in terms of the positions that have been expressed today, a certain amount of deference has been shown or expressed regarding the role of the State regulatory processing and the State commission in terms of addressing, perhaps, the issues raised by the ownership. I would submit that the record developed before the House on this issue speaks very clearly to the fact that the States do not, perhaps, believe that there are adquate capabilities at the State level to address these concerns, as well as the record that has been built before the committee today through the testimony offered by, particularly the witness speaking on behalf of NARUC.

There are issues raised in terms of the whole issue of utility involvement with cogeneration that I would refer the committee to in docket RN-81-2 before the Federal Energy Regulatory Commission involving geothermal facilities under PURPA, and the issue of more extensive electric utility involvement with geothermal facilities.

A particular application filed before the FERC which is currently under more detailed scrutiny involving Nornav Demonstration Geothermal Co., a report recently released by the Federal Trade Commission, Bureau of Competition on the prospects for cross subsidization in utility conservation activities; and finally some elements of the recent FERC study regarding fuel adjustment clauses, and some of the issues raised there in the context of captive coal mine activities on the part of electric utilities.

To summarize, Mr. Chairman, we believe, simply put, there are some electric utilities who perhaps feel threatened by the issue of disbursed power technology such as cogeneration. They believe that perhaps they have little to gain and are mounting massive sophisticated battles in the many issues raised involving purchase rates, standby rates, interconnections. Instead, there are other elements of the equation here who are proceeding in good faith attempting to implement a program consistent with the goals and objectives of the Congress, the FERC, and the State commission.

However, there are some rays of hope in the sense that some electric utilities, probably a minority number of utilities at this point, have started to view this issue a little bit different.

I quote from the recent annual report of one such utility wherein they state:

> We have no choice but to pursue these options. No new technology is on the horizon to replace nuclear and coal-fired central station generation, and both of these have considerably less than full public acceptance. Certainly never before has innovation been more important in meeting our challenge to provide economical and reliable effective service to our customers, and a fair return to our shareholders.

Mr. Chairman, this kind of attitude that I think is expressed herein, based upon the critical elements of good faith and cooperation, can never be legislated. Thank you.

[The prepared statement of Mr. Zimmer follows:]

WRITTEN TESTIMONY
OF THE
COGENERATION COALITION, INC.
ON THE
ROLE OF ELECTRIC UTILITIES IN COGENERATION
BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY REGULATION

April 19, 1982

The following written testimony is filed on behalf of the Cogeneration Coalition, Inc. on the role of electric utilities in cogeneration, and the issues raised in this regard as contained in S.1885 and S.1966 currently pending before this Subcommittee. The Cogeneration Coalition, Inc. (Coalition) is a non-profit organization comprised of interested natural gas utilities, industrial users, industrial equipment manufacturers, project developers and engineering and construction consulting firms. The Coalition has also established advisory working relationships with other public interest groups and national trade associations on issues affecting cogeneration development. The Coalition supports the provision of necessary financial and tax incentives to promote the utilization of cogeneration technology and the removal of unnecessarily restrictive federal barriers to the development of cogeneration potential nationwide.

Introduction

Cogeneration is one of the foremost technologies for the efficient use of energy currently available in the United States. It involves the sequential use of energy to produce electricity or mechanical shaft power and some other useful form of energy (usually heat or steam) from the same energy source. Major potential exists in the wood and pulp, steel, food processing, chemical and refining industries for the application of this technology. Other potential applications include water desalinization plants, multi-family residential complexes, universities, hospitals and military bases.

From the development of national interest in the promotion of energy conservation, the Congress has expressed concern and uncertainty with respect to the proper role of public utilities in the delivery of energy conservation services. This concern is primarily based on a belief that public utility involvement in unregulated markets for the delivery of energy-related services will potentially lead to the monopolization of these markets by interested public utilities.

This belief is reflected in certain provisions of the National Energy Conservation Policy Act of 1978 (NECPA), as amended by the Energy Security Act of 1980 (ESA). Pursuant to these statutory provisions, public utilities were required to participate in the delivery of energy conservation services initially to residential customers, and subsequently to customers in multi-family residential dwellings and small commercial buildings. However, the delivery of these services was circumscribed by various anti-competitive safeguards designed to prevent monopolistic or predatory practices by covered utilities under these Acts.

Congress' concern and uncertainty has not abated and has most recently resurfaced in the context of various proposals such as S.1885 to amend the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Power Act. These proposals would permit more extensive involvement by electric utilities in the development of cogeneration and a sharing in the benefits of certain rates based on avoided costs paid for cogenerated power purchased by the electric utility. These proposals to encourage electric utility investment in cogeneration have taken the form of specifically removing the 50% ownership test limitation in PURPA on electric utility ownership of cogeneration facilities, and the creation of unregulated subsidiaries by amendments to PURPA, the Federal Power Act, and the Public Utility Holding Company Act. These unregulated subsidiaries would engage in avoided cost transactions between parent and/or affiliate electric utilities while ensuring passthrough to ratepayers of the avoided costs paid to the unregulated subsidiary.

The Cogeneration Coalition, Inc. believes there are a variety of public policy questions which need to be discussed and solutions derived before a thoughtful final judgment can be made on proposals such as S.1885.

Summary of Positions and Recommendations

The Coalition expresses the following positions and recommendations which are discussed herein:

(1) The Coalition supports amendments to the Fuel Use Act and the Clean Air Act which correct severe restrictions on fuel choice and impediments to use of certain fuels in cogeneration facilities.*/

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*/ See generally, Written Comments of the Cogeneration Coalition, Inc. on Amendments to the Powerplant and Industrial Fuel Use Act filed with this Subcommittee on April 24, 1981

(2) The Coalition supports amendments to the Public Utility Regulatory Policies Act correcting the arbitrary size limitations imposed on small power production facilities.

(3) Before amending provisions of PURPA governing involvement and ownership by electric utilities of cogeneration facilities, the effectiveness of Sections 201 and 210 of PURPA must be fully evaluated. The Coalition respectfully submits that it is premature to conclude that these provisions as implemented by the FERC and the states have proven ineffective.

(4) If further action on these ownership issues is warranted, the Committee must thoughtfully weigh various factors discussed herein before proceeding with new legislation such as S.1885 at this time.

(5) If electric utilities are permitted expanded ownership opportunities through nonregulated subsidiaries, the structural, financial and operational issues and conditions posed also need to be addressed by state commissions.

The Question of More Extensive Utility Involvement is Premature

The Coalition suggests that action at this time on the issue of more extensive electric utility involvement in cogeneration must hinge on whether PURPA is perceived as effective in terms of promoting cogeneration development. We submit that this determination is still premature in recognition of various factors:

(1) Pending litigation involving various requirements of the FERC regulations and the constitutionality of Section 210 of PURPA must be resolved. This litigation has created uncertainty, a lack of stability, and some delay for cogeneration development.

(2) State compliance with these PURPA requirements was established for March 20, 1981. In that regard, substantial compliance was

delayed for a variety of reasons. As of January, 1982, only 34 states were in compliance with the PURPA requirements established by the FERC.

(3) Congress must recognize the 3-4 year lead time associated with the design and construction of cogeneration projects.

(4) Comparable issues are pending with respect to the implementation of the geothermal production provisions of the Energy Security Act amending PURPA. The FERC has identified several issues surrounding utility avoided cost transactions with subsidiaries for further scrutiny in Docket No. RM80-2. The Commission's action is in response to various concerns expressed by numerous state commissions during this proceeding.*/

(5) The larger issue of electric utility diversification is currently under study by an *ad hoc* task force within the National Association of Regulatory Utility Commissioners (NARUC). This task force has issued a draft report on the issue of diversification which will be subjected to hearings next month and the results of these hearings may have an important bearing on the issues raised in S.1885.

The Coalition believes that there is a need to promote certainty and stability with respect to the development of cogeneration facilities to permit their contribution to short and mid-term national energy objectives. Legislation that creates new requirements and the need for future implementing regulations at the federal level should be avoided by the Congress at this time.

Critical Factors Regarding More Extensive Utility Involvement

If this Subcommittee decides that further action on S.1885 is warranted, a number of critical issues must be resolved before definitive action is taken.

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*/ See more recently utility ownership issues posed for a geothermal facility in Nornev Demonstration Geothermal Company, FERC Docket No. QF82-48-000, Order Extending Time for Commission Action issued on April 9, 1982.

(a) Why Do Electric Utilities Want More Extensive Involvement?

The chief attraction to electric utilities for more extensive involvement with cogeneration centers on the potential for increased diversification and unregulated profits. When considering the financial condition of the electric utility industry, these considerations appear attractive and meritorious.*/ However, this issue raises a number of interesting subsidiary questions:

(1) Should electric utilities diversify and would this be beneficial to the ratepayers?

(2) Should such diversification be into areas posing direct application of experience and expertise or into non-utility areas?

(3) Does such diversification pose new business opportunities only for large companies entering new unregulated markets?

(4) Would such diversification exclude competition primarily from cogeneration facilities, small power producers, industrial users and gas utilities in providing electric services and satisfying power requirements?

(5) Does more extensive involvement by electric utilities impede the creativity and innovation exhibited by the private, non-regulated sector, or will it enhance and supplement those efforts?

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*/ An executive of one electric utility recently described the consequences of owning a cogeneration unit that produces electric power for 5¢ per kwh and sells it to the utility for 6¢. He said: "'The extra cent gets spread to all the systems' customers in such a way that it is infinitesimal... But for the utility it can mean one heck of a lot of dough.'" "Putting More Steam Into Electric Power Output," Business Week, March 15, 1982 at 154H.

(6) Would more extensive involvement foster less creativity in the efficiency and use of fuels for electric power generation?

(7) Does such an approach foster undesirable competitive activities within various market sectors for fuels, e.g. gas, oil and electricity?

(8) Could less than arms-length transactions occur with respect to the purchase and rates of excess power by the electric utility?

(9) If diversification is not a panacea, should its consideration be limited to just financially healthy utilities? Furthermore, what limits exist to ensure that the regulated side of the business is not abandoned in favor of the unregulated line of business?

(b) What Fuels for Cogeneration Would Be Used?

More extensive electric utility involvement could impose impacts on fuel choice and use patterns which will vary on a regional basis. Nevertheless, such decisions should be made in the market place and not subject to the artificial impediments imposed by the Fuel Use Act. Yet such market place determinations could be affected by the major position of the electric utility in cogeneration activities.*/ Some issues raised are:

(1) What impact on fuels choice might be exerted by the substantial purchasing power of the electric utility for primary fuels such as oil, gas and coal?

(2) Does this bulk purchasing power pose competitive difficulties for small cogeneration facilities?

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*/ See generally, FERC, Automatic Adjustment Clauses in Public Utility Rate Schedules (March, 1982) for a discussion of electric utilities that have diversified into coal mining through unregulated subsidiaries.

(3) How will the long-term contracting capabilities of the electric utility for oil, coal and use of unit trains, company-owned mines, etc. impact owners of small cogeneration facilities?

(4) Is there a need for a coordinated policy on these issues at the federal level, or should these concerns be more properly addressed at the state level? Should these concerns be treated on a case-by-case basis or on a generic basis?

(c) How Diverse Is the Electric Industry and What Is the Market Structure?

The electric industry is not homogeneous, but is comprised of the investor-owned, municipal and rural cooperative sectors. Further, there are various combination utility companies providing both gas and electric service. This market structure indicates the difficulty in applying uniform or standard federal solutions to the heterogeneous sectors within the industry.

(d) Are Financial Conditions Really Conducive to Such Diversification?

The recent reports by the Administration's energy transition team, the FERC hearings in March, 1981 and the recent hearings before the Congress have heightened public awareness of the financial plight of the electric utility industry. These developments have focused on the inability of the industry to finance large-scale capital construction programs and the current impacts on electric utility equity and debt issuances. Various recommendations have been spawned from these discussions ranging from more favorable treatment of construction work in progress to deregulating certain sectors of the electric industry. Several groups are studying these issues in greater detail at this time including the White House Cabinet Council, DOE, EEI and NARUC.

In a recent article entitled "Electric Utilities: Thinking the Unthinkable" appearing in the March 23, 1982 Wall Street Journal, the financial plight of electric utilities was described as follows:

> Surplus capacity is fast disappearing. Even if reduced energy demand continues, the U.S. will start bumping up against estimated energy supply by late in this decade. And given the time lags involved in bringing new facilities on line, some observers are forecasting brownouts, deteriorating service and curtailment of use by 1990.
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> The financing needs in this decade will be between $500 billion and 4600 billion--over half of which must come from the credit markets. There is no guarantee that deregulation will release a torrent of new capital, but given the current state of the industry under regulations, it's no wonder that deregulation is being viewed with more than polite interest by all concerned.

The financial conditions of the industry have a bearing on the issue at hand in several important respects:

(1) Where will the capital for electric utility diversification in cogeneration originate in light of current industry financial conditions?

(2) With limited capital availability and numerous calls on capital resources, is diversification sound in light of other competing goals such as environmental compliance?

(3) If difficulty is experienced in financing the utility system's own plant and construction program, how will the utility finance new ventures in unregulated subsidiaries?

(4) Given the present financial condition of the electric utility industry, would capital be better spent pursuing economies of scale through power pool arrangements and electricity imports rather than through diversification into new business?

(e) Are Unregulated Subsidiaries Really Necessary?

There may be more effective approaches to the delivery of cogeneration services than by permitting electric utilities to establish unregulated subsidiaries and/or affiliates. Before reaching a definitive answer, some questions must be answered:

(1) Why haven't third party arrangements proven an effective approach under current requirements for the promotion of cogeneration development?

(2) Can more management agreements and service contracts be utilized to address utility concerns with reliability, interconnection safety, backup power requirements, excess power sales?

(3) Can cogeneration fit into the needs of power pool arrangements in terms of central dispatching and wheeling to other electric utilities with various capacity and reserve margin requirements?

(4) Why haven't more multi-party cogeneration projects been pursued involving joint ventures with multiple parties including the electric utility?

(5) Why are some utilities proceeding with cogeneration subsidiaries even in light of the 50% ownership test under PURPA?

(f) Are Anti-Competitive Concerns Real or Transparent?

There are a number of anti-competitive issues raised by the entry of regulated electric utilities into an unregulated market. In this regard, comparable issues of concern are not currently posed with respect to natural gas utilities promoting cogeneration since they do not generally deliver electric services, nor generate electricity. Under current federal antitrust authorities embodied in the Sherman Act, the Clayton Act and the Federal Trade Commission Act as well as current state antitrust authorities, the FERC and state commissions can evaluate such considerations along with the FTC, the Justice Department and state attorney generals. Among the issues to be focused upon are:

(1) What is the likelihood of cross-subsidization between the regulated and non-regulated companies whereby the regulated company could divert profits to subsidize the pricing patterns offered in competitive markets by non-regulated subsidiaries?*/

(2) Does the potential for tying arrangements exist?

(3) Can problems of access be created for small cogenerators and private development companies because of the position in the market place of an electric utility?

(4) What is the prospect for higher rates to be charged by the regulated company with a non-regulated cogeneration subsidiary?

(5) Does the risk of a certain imputation of profits derived from unregulated subsidiary or affiliate operations back to the regulated company mitigate concerns regarding anti-competitive impacts?

(6) Can independent operating subsidiaries or affiliates be created? What relevant experiences can be derived from the states of New York and Connecticut's experience?

(7) Would an unregulated subsidiary have better access to staff and energy usage information than a private development company if current efforts to repeal Section 133 of PURPA cost of service information reporting are successful?

(8) Do meaningful experiences exist as derived from the regulated gas utility industry "total energy system" concept in the late 1960's - early 1970's that are applicable to cogeneration development today?

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*/ A working paper by the staff of the Bureau of Competition of the Federal Trade Commission has articulated fully the antitrust problems of Cross-subsidization where a utility engages in unregulated energy conservation markets. "Competion and Utility Cross Subsidization of Energy Conservation Activities," working paper of the staff of the Bureau of Competition, Federal Trade Commission (1981).

Conclusion

The Cogeneration Coalition submits that these issues must be confronted by parties interested in cogeneration development before substantive decisions are reached regarding the need to amend PURPA as contemplated in legislation such as S. 1885. Enactment of S. 1885 would be premature at this time and should await the conclusion of various studies being undertaken by the White House, DOE, NARUC and the electric utility industry on the broader issues of electric utility diversification. This more prudent and cautious approach is absolutely essential and would offer the certainty and stability so necessary and so lacking for cogeneration development since 1980.

We thank you for the opportunity to present this testimony, and we commend this Subcommittee for exploring these issues relevant to the development of cogeneration potential nationwide.

Senator **Humphrey**. Thank you. Mr. Brown?

STATEMENT OF PETER W. BROWN, DIRECTOR, ENERGY LAW INSTITUTE

Mr. **Brown**. Thank you. It's a pleasure for me to be here today. You have my prepared statement and I would have it included in the record.

I just want to make a few brief remarks in response to some things that have been said here before. First, I agree with the representatives of the Edison Electric Institute. There is going to be greater access to capital made available if this bill is passed, permitting greater participation by the electric utility industry in qualifying cogeneration in small facilities. I might add I generally favor the bill as it is drafted.

Second, we shouldn't lose sight of this. This bill will inject more competition into the cogeneration of the electric utility industry and in the cogeneration of small power production markets. I say this because we have to bear in mind that the bill applies to all utilities. Not only investor-owned utilities, but the municipal utilities and the cooperatives who are also electric utilities as defined under PURPA.

I don't for one moment put to one side that these utilities will forego the opportunity to participate with cogenerators in small power production facilities. Not only in their own service territory, but outside.

The second thing that we're talking about here is cogeneration, small power production participation by the electric utility industry, wherever that qualifying facility may be located. It may not necessarily be located in the electric utility service territory. It may be located in someone else's service territory. In those circumstances there are two things to happen. No. 1, we can assume that the qualifying facility in which the electric utility participates which is located outside of the territory in some other electric utility service territory will negotiate at arms length with that other electric utility for the sale and purchase of electric power. That kind of an arrangement is not going to raise problems of public utility regulatory scrutiny that Ms. Shanaman has pointed to.

Second, I think if we're talking about out-of-service territory involvement by the electric utility industry in qualifying facilities we have to deal with inter-connection provisions presently within the Federal Power Act in sections 210 and 212 and the problems created by the AEP case. I think that is simply done by an amendment to this legislation which confers discretion under section 210 to promulgate fair and equitable regulations, and that should be done. It should be done not only to deal with the situation created by this bill but to deal with the uncertainties created by the AEP case.

Those are the main thrusts of my observations. I am concerned about the involvement that the electric utility industry and qualifying facilities to the extent there is the spector raised of them stalling the negotiations in power purchase contracts and inter-connection arrangements so as to favor their own facilities as opposed to others.

I might point out that, No. 1, there is a requirement of nondiscriminatory application of all interconnection standards and ratemaking standards and I think the Regulatory Commission in the State can scrutinize those arrangements to insure there is no discrimination.

Second, that I also note that where the utilities drag their feet, and I'm in agreement with the Edison Electric Institute people on this, the public utility commissions have major sanctions that they can impose. I know the State of Maine PUC has just indicated that it will reduce the allowed rate of return of one investor-owned utility company in the State of Maine because it has been reluctant to negotiate power purchase contracts with cogenerators, and I noticed California has done the same thing in the past.

So the sanctions are very powerful and they are there and they are available to be used.

Finally, with respect to controls by State PC's there are in place a number of traditional public utility controls. They are the ability to scrutinize arrangements between affiliated interests. They are the ability to determine whether or not expenses incurred by the operating electric utility are prudent and they do have control over financing and capitalization of qualified facilities.

Given all this I think the bill is a good one and I urge that it be adopted with the amendment that I have indicated.

Thank you.

[The prepared statement of Mr. Brown follows:]

PREPARED STATEMENT

S. 1885 and S. 1966

BEFORE THE

SUBCOMMITTEE ON ENERGY REGULATION

By

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Director

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TABLE OF CONTENTS

Page

S. 1885 and S. 1966:
97th Congress of the United States

I. Introduction and Summary of Testimony 2

II. S. 1885 Should Be Enacted As Proposed With Two Amendments: The First Amendment Would Assure Equal Treatment for Purposes of Exempting Utility Owned Qualifying Facilities from Certain Utility Regulation and the Second Amendment Would Clarify the Status of the Interconnection Regulations Promulgated by the Federal Energy Regulatory Commission. 4

III. S. 1966 Should Be Enacted As Proposed 11

S. 1885 and S. 1966

97th Congress of the United States

The Energy Law Institute (ELI) of the Franklin Pierce Law Center has been engaged in a number of studies of the problems of implementation of Title II of the Public Utility Regulatory Policies Act over the past four years. This activity has involved the staff of ELI in testifying before numerous state regulatory agencies on Title II, assistance to some fifteen state regulatory agencies in the implementation of Title II, assistance to the Tennessee Valley Authority and participation in numerous workshops and conferences on Title II throughout the United States. ELI has also been engaged by a variety of developers to assist them in power purchase arrangements and related financing activities. Peter W. Brown, Director of ELI and Professor of Law at the Law Center, has been principal investigator on several of the studies noted above and has been actively involved in the activities of ELI concerning Title II of PURPA. Professor Brown also teaches Energy Law and Policy and Public Utility Regulation at the Law Center.

A list of publications of ELI are attached to this Statement. Copies of these publications may be obtained either through the National Technical Information Service (NTIS) where NTIS numbers are indicated or directly from ELI.

I. Introduction and Summary of Testimony

This testimony urges enactment of S. 1885 with two amendments and S. 1966 as proposed. The two amendments proposed to S. 1885 do not change the thrust of the bill but rather are designed to further the purposes of the bill. Of the two bills S. 1885 will have the most substantial impact on electric utility regulation.

There are three very important aspects of S. 1885. The first is that the bill will, through the ability of the electric utility industry to raise capital, provide varieties of more flexible financing arrangements for developers of cogeneration and small power production facilities and introduce an additional competitive element into the market for cogeneration and small power production facilities.

The second, and most important, is that bill will encourage electric utilities to establish subsidiary or affiliated qualifying facilities outside of the parent's service territory and, hence, will encourage greater competition among utilities within the electric industry itself.

The third important aspect of S. 1885 is that it presupposes that existing, traditional public utility regulation is in place to curb any potential abuses. In those instances where the utility parent is purchasing and selling power from and to its subsidiary in its service territory, regulatory authority presently exists at the state and federal levels to scrutinize and control the activities of the parent, to prevent anticompetitive behavior and to curb abuses which otherwise may have been passed on to the parent's ratepayers.

The two areas of S. 1885 which bear amendment deal with the discretion of FERC to exempt qualifying facilities from federal and state traditional utility regulation and to promulgate workable interconnection regulations for qualifying facilities under Section 210 of PURPA.

It is important to electric utilities which are not registered or exempt holding companies under the Public Utility Holding Company Act to avoid imposition of the onerous requirements of the Holding Company Act. It is also important to assure parity of treatment between subsidiary qualifying facilities and qualifying facilities which are not subsidiaries of electric utilities. Accordingly, it is urged that an amendment be adopted requiring the Federal Energy Regulation Commission to treat subsidiary facilities in the same manner as independent qualifying facilities for purposes of their exemptions from utility type regulation under Section 210 of the Public Utility Regulatory Policies Act (PURPA).

The second amendment is designed to cure the problem created by the decision of the D.C. Circuit Court of Appeals in the American Electric Power (AEP) case. If qualifying facility subsidiaries are going to be operating outside of the service territory of the parent, workable and equitable interconnection standards will have to be in place. The AEP case declared invalid the workable and equitable interconnection regulations which the Federal Energy Regulatory Commission promulgated under Section 210 of PURPA. What is left are the unworkable procedures, standards and conditions for interconnection which are part of other sections of the Federal Power Act. Accordingly, an amendment is urged authorizing the Federal Energy Regulatory Commission to promulgate interconnection standards notwithstanding other provisions of law.

With respect to S. 1966, there are numerous groups in the field which will publish parts or all of the data to be reported under present law. Moreover, the reporting requirements are unreasonably burdensome. Hence, it is urged that S. 1966, which substantially eliminates certain reporting requirements, be enacted.

II. S. 1885 Should Be Enacted As Proposed With Two Amendments: The First Amendment Would Assure Equal Treatment for Purposes of Exempting Utility Qualifying Facilities from Certain Utility Regulation and the Second Amendment Would Clarify the Status of the Interconnection Regulations Promulgated by the Federal Energy Regulatory Commission.

The proposed bill changes the definitions of "qualifying small power production facility" and "qualifying cogeneration facility" by eliminating language which prohibits ownership of such facilities by electric utilities. See Section 3(17)(c)(ii) and (18)(B)(ii) of the Federal Power Act, 16 U.S.C. § 796.

The Federal Energy Regulatory Commission (FERC) has promulgated regulations which further define the ownership restrictions for electric utilities. See Section 292.206, 45 Fed. Reg. 17973 (March 20, 1980) of FERC regulations. Under Section 292.206 a qualifying small power production facility and a qualifying cogeneration facility (hereinafter collectively referred to as "qualifying facilities" or "QFs") may not have more than 50% of its equity capitalization owned by an electric utility.

It should be noted that because of the expanded definition of an "electric utility" under Section 201 of the Public Utility Regulatory Policies Act of 1978, state and municipal electric utilities and cooperative electric utilities as well as investor owned electric utilities are barred from ownership of more than 50% of an equity interest in a QF.

The effect of the present prohibitions against utility ownership of QF's is to burden unreasonably electric utility participation in a growing market. At the present time much of this market, especially the market for the development of wind farms, small scale hydroelectric facilities and biomass facilities, is in need of access to capital markets and confronted by high interest rates and financing. Needed capital and financing assistance can be provided by the electric utility industry but for the present restrictions on utility participation. Moreover, in addition to the access to capital provided by the electric utility industry, removal of the ownership restrictions will permit greater participation by the electric utility industry in a market in which that industry has considerable technical expertise.

To illustrate the problem, it is assumed that there is an economically viable 5 MW QF which is owned by a non-utility developer. In order to finance the project, it is assumed that the maximum debt-equity ratio for the project is 65% debt to 35% equity. This debt-equity ratio is compelled by the high interest payments (very possibly based on a variable rate formula) required for the long term financing and the fact that, while project revenues over the financing life of the project yield competitive terms to the investors, the revenues in the early years barely, or even do not, cover debt service requirements. In this situation an electric utility may be interested in providing part of the long term debt (at its rates which are probably lower than those of the developer) but may require for purposes of protecting or enhancing its returns on its investment a greater than 50% share of the equity. Under present law the electric utility, of course, cannot participate and this project, while economically feasible over its ten to twenty year investment period, will not be built.

A second benefit of the proposed bill is that it will inject more competition into the QF development market and into the market for the generation of electricity as a whole with marginal and probably no danger for abuse. This benefit naturally occurs because electric utilities under the proposed legislation are given greater flexibility in entering the market. More importantly, however, the bill would encourage electric utilities to form QF's at locations outside of their service territories and, accordingly, will encourage competition at the generation level among members of the electric utility industry itself.

The bases for this reading of the bill are the logical implications of the bill itself and the fact that QF's also qualify for an exemption from state public utility type regulation and provisions of the Public Utility Holding Company Act under FERC regulations promulgated pursuant to Section 210 of PURPA. See Sections 292.601 and 292.602, 45 Fed. Reg. 12237 (Feb. 25, 1980). Again, some examples are useful to illustrate the point. If an electric utility establishes a separate subsidiary to enter the QF market that subsidiary QF, absent any inhibition under state law, could and would develop a viable project which is not located in the service territory of its parent.

Section 292.602(b) of the exemption regulations cited above declares that QFs are not an "electric utility company" under the Public Utility Holding Company Act. The Public Utility Holding Company Act applies only to companies that own a controlling interest in an electric or gas utility. If follows that since the subsidiary QF in the example cited is "not an electric utility" under FERC regulations, the parent electric utility is not, merely because of its controlling interest in the subsidiary QF, a holding company for purposes of the Holding Company Act and would not be subject to its onerous requirements.

A similar conclusion may be reached in this example, where the QF subsidiary does business in a state other than the state in which the parent utility has its operations and which state is not contiguous to the state of the parent's operations. Here, by the same reasoning used for the previous example, since the QF subsidiary is not an electric utility under the FERC regulations the parent utility cannot be deemed to hold a controlling interest in an electric utility for purposes of the Public Utility Holding Company Act. Hence, the parent is not a holding company subject to the onerous requirements of that Act. Moreover, under Section 292.602(c) of the FERC regulations the QF subsidiary would not be subject to utility type regulation in the state where it does business.[1]

It should be noted also at this point that the proposed bill is not limited to the investor owned utility segment of the electric utility industry. Presumably, subject to the constraints of state and local law, municipal, state and cooperative electric utilities could establish QF affiliates and initiate QF operations. Such activities by municipal and cooperative electric utilities can only increase competition within the industry.

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[1] Of course if the utility parent is already one of the 13 operating registered holding companies the parent would still be subject to the Public Utility Holding Company Act. If it is already an exempt holding company, again the parent would be subject to the Public Utility Holding Company Act. The examples are designed to show the beneficial effects of the bill on those numerous utilities which are neither registered nor exempt holding companies.

Finally, there is a third important underpinning for the proposed bill and that is found in the traditional utility regulation presently in place at the federal and state level. In the situation where an electric utility establishes a QF and power is exchanged between the two entities there are several traditional regulatory controls which would deter abuse arising from that relationship. First, state regulatory commissions have the authority to approve or disapprove arrangements between affiliated interests. Second, to the extent that power purchased by the parent incurs an expense of doing business, state regulatory commissions may for ratemaking purposes disapprove or approve in whole or in part such an expense. Third, state regulatory commissions have the authority to approve or disapprove financing arrangements needed to capitalize a QF subsidiary. It should be noted here that the state authority cited above is directed at the parent utility and the results of the exercise of such authority would be felt by the parent utility. Hence, the exercise of this authority would not be inhibited by the exemption regulations referred to earlier. Similar authority is vested in FERC with respect to arrangements between a subsidiary QF and a parent which sells power at wholesale in interstate commerce under Part II of the Federal Power Act.

Of course, in the situation where the QF subsidiary was located outside of the service territory of the parent, the arrangement between the QF and purchasing utility would, in almost all instances, be a bona fide arms length arrangment. If it is not bona fide arms length, the regulatory controls cited above are in places to prevent abuse.

Having set forth the benefits and advantages of the proposed bill, it is useful to point out some of its potential difficulties. The first difficulty concerns the exemption from provisions of the Public Utility Holding Company Act under Section 292.602(b) of the FERC regulations. Under Section 210 of PURPA, FERC is given the discretion to exempt QF's from utility type regulation at the state level, Part II of the Federal Power Act and the Public Utility Holding Company Act. FERC wisely chose to use its full power under the exemption provisions of Section 210 of PURPA by promulgating Section 292.602 of the regulations.

However, FERC could, under Section 210, choose not to exempt QF's controlled by electric utilities from state utility type regulation or the Public Utility Holding Company Act. It would indeed be unfortunate if FERC chose to exercise its discretion in this way. Accordingly, amendatory language should be considered to require FERC to treat QF's which are subsidiaries of electric utilities for purposes of the exemption provisions of Section 210 in the same way as other QFs are treated.

The second difficulty with the bill deals with the ramifications of the decision of the D.C. Circuit Court of Appeals in American Electric Power Co. et al v. the Federal Energy Regulatory Commission et al, No. 80-1789 (D.C. Cir. Jan. 22, 1982). As discussed at some length, this testimony views the prospects of QF subsidiaries of electric utilities locating outside of the service territory of the parent as an important and salutory injection of further competition into the generating sector of the electric utility industry. The AEP case and especially that part of the decision which held invalid the interconnection regulations promulgated by FERC under Section 210 of PURPA pose a threat to QF subsidiaries operating outside the service territory of the parent. In AEP, the Court of Appeals ruled that because there were specific and detailed provisions in other sections of the Federal Power Act dealing with procedures, standards and conditions for interconnection between QFs and other electric utilities, FERC had no inherent authority under Section 210 of PURPA to promulgate its interconnection standards for interconnection between QFs and utilities. The interconnection standards promulgated by FERC under Section 210 of PURPA were and are equitable, thoughtful and workable standards for interconnection arrangements between QFs and utilities. The procedures, standards and conditions under the other sections of the Federal Power Act are cumbersome, in some instances inconsistent and substantially unworkable.

In those situations where a QF subsidiary operates outside of the service territory of its parent, especially where the QF is an affiliate of a municipal or cooperative utility operating in the service territory of an investor owned utility or vice-versa, the interconnection procedures, standards and conditions under the Federal Power Act could pose real and substantial barriers to operations of the QF. The FERC interconnection standards under Section 210 of PURPA are, as noted, considerably more workable and provide such QF's with access to a market on an equitable basis.

Accordingly, it is urged that S. 1885 be amended to grant FERC the authority under Section 210 to promulgate interconnection regulations for interconnection arrangements between QFs and utilities, notwithstanding any other provisions of law.

III. S. 1966 Should be Enacted As Proposed

This bill substantially reduces reporting requirements, under Section 116 of PURPA, for state regulatory commissions and unregulated utilities on their activities under the ratemaking standards of Title I of PURPA. These reporting requirements are unnecessary, extend for an inordinate period of time and will contain information which has been and will be reported by other groups and organizations interested in the field of public utility regulation.

The groups and organizations in the field which have published and will continue to publish ratemaking activities of regulatory authorities and unregulated utilities are the National Association of Regulatory Utility Commissioners (NARUC), the National Regulatory Research Institute (NRRI), the Electric Power Research Institute (EPRI), the American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) among others. Moreover, it is ventured that the reports published by these groups will be given far greater dissemination than those rendered to the Secretary of Energy under the present Section 116. Accordingly, it is urged that S. 1966 be enacted as proposed.

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DOE/RA/04934-06 ELI-79-9	EXECUTIVE SUMMARY: LEGAL OBSTACLES AND INCENTIVES TO SMALL SCALE HYDROELECTRIC DEVELOPMENT IN THE MID-ATLANTIC STATES, May 1979 (Delaware, Maryland, New Jersey, New York, Pennsylvania, Virginia)
DOE/RA/04934-08 ELI-79-29	EXECUTIVE SUMMARY: LEGAL OBSTACLES AND INCENTIVES TO THE DEVELOPMENT OF SMALL SCALE HYDROELECTRIC POTENTIAL IN THE SEVEN MID-WESTERN STATES, August, 1979 (Illinois, Indiana, Kentucky, Michigan, Ohio, West Virginia, Wisconsin)
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ELI-80-21	LEGAL OBSTACLES AND INCENTIVES TO THE DEVELOPMENT OF SMALL SCALE HYDROELECTRIC POWER IN MASSACHUSETTS, Rev. August 1980
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DOE/RA/04934-14 ELI-79-19	LEGAL OBSTACLES AND INCENTIVES TO THE DEVELOPMENT OF SMALL SCALE HYDROELECTRIC POWER IN NEW YORK, August 1979
ELI-79-35	LEGAL AND INSTITUTIONAL OBSTACLES AND INCENTIVES TO THE DEVELOPMENT OF SMALL SCALE HYDROELECTRIC POWER IN NORTH CAROLINA, September 1979
DOE/RA/04934-26 ELI-79-26	LEGAL OBSTACLES AND INCENTIVES TO THE DEVELOPMENT OF SMALL SCALE HYDROELECTRIC POWER IN OHIO, August 1979
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ELI-80-7	LEGISLATIVE OPTIONS AND RECOMMENDATIONS FOR FACILITATING HYDROELECTRIC DEVELOPMENT IN NORTH CAROLINA, 1980
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ELI-79-8	REPORT TO THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION: RE THE IMPLEMENTATIONS OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 TO CERTAIN PROCEEDINGS BEFORE THE N.H. P.U.C., April 1979
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ELI-79-40	COMMENTS ON THE PROPOSED REGULATIONS IMPLEMENTING SECTION 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978, FERC Docket RM79-55, December 1979
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ELI-80-14	STATE IMPLEMENTATION OF THE REGULATIONS PROMULGATED PURSUANT TO SECTION 210 OF PURPA: Implementation Options, June 1980
ELI-80-15	REGULATORY ISSUES PERTINENT TO THE IMPLEMENTATION OF SECTION 210 OF PURPA, June 1980
ELI-81-4	IMPLEMENTATION OF SECTION 210 OF PURPA IN THE FIFTY STATES, (updated monthly)
ELI-81-5	A SUBSTANTIVE SURVEY OF THE IMPLEMENTATION OF SECTION 210 of PURPA

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Summary of "A CONFERENCE FOR NEW ENGLAND: LEGAL AND INSTITUTIONAL OBSTACLES AND INCENTIVES TO SMALL SCALE HYDROELECTRIC DEVELOPMENT," January 30-31, 1979,

DOE/RA/04934-04

Summary of "SMALL SCALE HYDROPOWER IN THE MID-ATLANTIC STATES: RESOLUTION OF THE BARRIERS IMPEDING ITS DEVELOPMENT," May 4-5, 1979, Washington, D.C.

DOE/RA/04934-05

Summary of "SMALL SCALE HYDROPOWER IN THE MIDWEST: AN OLD TECHNOLOGY WHOSE TIME HAS COME," November 14-15, 1979, Detroit, Michigan

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Senator HUMPHREY. Thank you, Mr. Brown.

It occurs to me as a witness you are in a somewhat unique circumstance here in that you represent neither a producer of power in a utility or nonutility, nor a user. Is that correct?

Mr. BROWN. That is correct.

Senator HUMPHREY. You might be regarded as a neutral party.

Mr. BROWN. I might be.

Senator HUMPHREY. At least at the outset. I think, without taking unfair advantage, it is useful to point out that you are a professor of law at the Franklin Pierce College, Energy Law Institute.

Mr. BROWN. That is correct.

Senator HUMPHREY. What was the impetus for your study into this area?

Mr. BROWN. Our impetus was largely due to some requests by the Federal Government for us to do research into areas where there were regulatory barriers or institutional barriers with the development of alternative energy resources including small-scale hydro in the New England area and a variety of other sources.

As Mr. Nicholson has indicated, longstanding institutional arrangements in this area indicated great ambitions to development of small power production facilities by the nonelectric utility industry. PURPA went a long way and the FERC regulations went a long way to insure those institutional barriers. Now we're talking with respect to this bill, the idea of injecting more competition into this market and I think of making available more capital through the electric utility industry and I again stress we're talking about municipal and State-owned utilities, cooperatives and investor-owned utilities who have access to capital which may be greater than the access to capital presently available for other small qualified facilities.

Senator HUMPHREY. The Institute has conducted a number of studies into the disincentives, the obstacles to greater development of hydro facilities.

Mr. BROWN. Yes.

Senator HUMPHREY. So your motivation here is simply to find ways to encourage development of hydro power.

Mr. BROWN. Among other sources of electric generation, yes.

Senator HUMPHREY. You have given PURPA credit, and almost everyone will, for going a long way to encourage that kind of development. What do you think of the assertion that we haven't given PURPA enough time yet to work in the context of this bill?

Mr. BROWN. I think we've given PURPA enough time to work in the context of this bill. This bill is a relatively simple bill. All it does is open up cogeneration and small power production to greater participation by the electric utility industry. I've given an example in my prepared statement where it may be necessary in order to finance a project or a utility to take more than a 50-percent ownership in a project. That can be for a whole variety of reasons.

The project may be a good one but it may not be able to be financed without that kind of participation. To the extent that this bill makes available additional participation by the electric utility industry, we are encouraging something that hasn't been encouraged before.

Our experience has been in providing technical assistance to some 15 State regulatory authorities and to TVA, that the State Regulatory Commissions are working on these problems. They've been working on them sincerely and diligently and they're doing a good job for the most part. There will be some falling out in the implementation process. There will be some experiments, but that's all to the good. That's what State Regulatory Commissions are for, to figure out what is best for the particular environment of their State. But I don't believe the process of implementation would be at all affected by this bill measurably. I don't think it will be thrown back or thrown into confusion.

Senator HUMPHREY. If this bill were enacted, how would that affect the ability of nonutility companies to obtain financing for cogeneration in small power production? In other words, can you address the suggestion that the bill would enable the utility companies to come in and pretty well take over this field, crowding others out?

Mr. BROWN. I don't see it. The cogeneration is site specific. There will be a number of industrial cogenerators which will own their own facility. I can't imagine an electric utility walking in there and taking over their plant. They will have to work out some voluntary amicable arrangement with the industrial cogeneration owner.

As you know with respect to small scale hydroelectric development, FERC controls the process as to who gets those sites. With respect to wind farms, again, they are very site specific. Whoever has access to the property on which the wind farm is located will pretty much control any arrangements with whatever utility participant that happens to be.

With respect to other biomass plants such as wood chips and the like, again, you're talking about access to sources of fuel and wood chip supply. Most of these arrangements I see are going to be utility qualifying facility partnerships. And to the extent that some of these arrangements cannot be financed because the utility which is willing to go into the partnership on something more than a 50 percent basis, is prohibited now in the present FERC regs from doing so and protecting its investment that way. Thus projects won't be financed, and that's a loss.

To reiterate, I don't think that new arrangement proposed by the bill is going to throw this whole area into uncertainty and doubt.

Senator HUMPHREY. Let me ask that same question to other witnesses.

Mr. NICHOLSON. Speaking to the question of utility development and financing, and so forth, I think a case that comes to mind in Cattle Falls, Wash., is probably of interest.

There were two competing projects. One from what we know of it by a group of lumber mill owners who presumably had access to the wood. The other by the local utility. The local utility is building a 100-percent owned 40-megawatt wood-fired powerplant. Presumably it's building it on the premise that it will get whatever the appropriate rate of return is allowed to it by the utility commissions governing its activity, both in the State of Washington and the State of Idaho. It's particularly so with the Washington Water Power.

The utility has gone ahead, and to our knowledge it has ordered the boiler which is a considerable financial commitment. It has all the permits. The lumber companies didn't seem to get anywhere with this particular endeavor, although their activity is claimed yet to be ongoing, and they are in some kind of negotiation, I understand, with the Bonneville Power Administration. So we have an example here where the existing system or the utility chose to build something that would be a qualifying facility on the belief that it was the proper thing that it should build and the least cost thing that should go into its generating plants.

Senator **Humphrey**. In the case you've cited, the utility involved apparently was not proceeding under the benefits of PURPA.

Mr. **Nicholson**. It just went ahead on its own.

Senator **Humphrey**. The utility can go ahead and do that anytime it wants.

Mr. **Nicholson**. That's exactly the point. This kind of facility is built by utilities under those conditions right now, for good and logical reasons.

Senator **Humphrey**. But that's apparently a rare exception. It's the only one that I've heard of.

Mr. **Nicholson**. We suggest that you might consider hydro sites the utilities are involved in, many of which qualify. The areas that I look at in the Federal Register, a number of utilities are involved in filing on sites, that I believe made the qualifications, so there are endeavors there.

Mr. **Jamison**. I could cite another example.

Senator **Humphrey**. If you would address the whole question please.

Mr. **Jamison**. Now let me start with an example of how we feel it's not necessary to have this change in law.

My company, in working with Eugene Watt Electric Utility Co. in Springfield, Oreg., put together a joint project. In this particular case the utility owned the equipment 100 percent. Weyerhaeuser operated the plant and leased land to the utility for the purpose of installing it. The Weyerhaeuser gets a fee for operating the plant and buys the steam back from the utility. The utility sells electricity to the cities in Burbank, Glendale, and Pasadena. That's an arrangement that was worked out cooperatively without the need for a law such as your proposal. And we believe those kinds of arrangements are still possible and still feasible, although we agree that it takes a great deal of cooperation between the utility and a nonutility entity. That there has to be a considerable amount of dedication to working out a solution, and there has to be mutual trust and respect with those that are involved.

I think there is no question that it can be done.

The second point that I would like to make is, in December in the Federal Register, you indicated there was a total of about 1,800 megawatts of cogeneration and I guess small power production that were currently coming along. That figure has considerably increased now. We checked with the FERC staff this morning and we learned there is something like 3,100 megawatts and it has more than doubled in the 6 months, so it sounds to me like PURPA is doing the job and I would say it just needs a little more time to get going.

It takes a while for any new law to really become understood and get cranked into the longer range planning of the larger corporations which are principally the source of this additional cogeneration.

Mr. ZIMMER. Let me restate the question. It's been a while since it was originally asked, and that was the impact of the bill on the financial capabilities of these types of projects. Utility financing vis-a-vis private sector nonutility financing.

Senator HUMPHREY. If this bill were to pass, how would it affect the ability of nonutility parties to obtain financing and put together these agreements?

Mr. ZIMMER. A number of the nonutility financing approaches are basically focusing on generally and in a simple fashion the conventional type of approaches. They are utilized by electric utilities, more unconventional types of approaches involving third-party finances, perhaps in some instances use of recently enacted tax provisions and Economic Recovery Tax Act, and so forth.

I think if an electric utility were able to come in and finance these types of projects, you would see a situation, particularly under economic circumstances like today, where competitive financing options from nonutility sources just could not be brought to bear on a comparable basis. Maybe in a more flush economic situation it would be a difference, or more of a competitive balance in terms of options, but I just don't think that would occur today.

I think that competitive situation is really the root of why this type of provision was enacted in 1978. It was perceived and deemed desirable that this type of competitive imbalance that existed pre-1978 needed to be brought into focus and into balance. And the question today once again is, Has that desire, has that effort still proved to be useful or necessary? I think we are all here submitting yes it was.

I go back to my original point. The condition, is PURPA not working? I don't think we can say that it is not working at this point in time.

Third, I would add, let's take a look at this bill. This bill was introduced on the House side a year ago when less than 15 States had enacted the FERC requirement to implement PURPA. It was enacted in the Senate side last fall when about 25 States had moved forward to enact PURPA at that time.

By the end of January this year 34 States sat in a position where PURPA had been fully enacted at the State level vis-a-vis the FERC regulations and requirements.

Senator HUMPHREY. You are suggesting that the companies involved in cogeneration would be unable to get financing if the bill were to go forward. Staff has pointed out to me that the members, for instance, of the Industrial Boiler Owners Council are some of the biggest companies in the country: Procter and Gamble, Hercules, Weyerhaeuser, Kaiser, Republic Steel, Anheuser Busch. If companies like these can't get financing at a time when utilities which are in financial trouble can, it seems to make the case for the bill.

Mr. ZIMMER. I didn't say that these companies couldn't get financing. I made the point that I think alternatives, that I think competitive alternatives would be available, the options that could be assessed from financing might not be the same if this bill were enacted. Our statement, particularly on page 9, it raises some questions that I think also need to be addressed in terms of the financing issue that you are focusing upon. You know we all are vigilant in understanding the capital shortfalls within the electric utility industry and where would this incremental financing become available to cogeneration or dispersed power projects in that environment? Is that really, I think as we have indicated, second, a sound goal, or vis-a-vis other more desirable objectives that need to be assessed by electric utilities.

Third, a critical point too is, are there other options or alternatives for them to scrutinize and analyze the terms of power calling arrangements in poor projects options which are under scrutiny, particularly in your State, to address the supply capacity shortfall issue that we are focusing upon.

Mr. BROWN. Mr. Chairman, may I embellish on my remarks just a minute? It seems to me there are three alternatives for financing that are available, and I think this bill is going to help out in one area. You mentioned the names of the industrial association. For the most part they will be able to internally finance a good cogeneration project and will not need access to capital.

The other situations, where you have an absolutely dynamite project which can be construction financed and long-term financed, basically on an as-available basis where you don't need any security because it's such a very good project.

The third kind of project that I think this bill is going to help, and this is limited impact of the bill, is where you have a project that cannot be internally financed. It's a marginal project from the financing standpoint, but it has to be financed on the basis of the stream coming from the project in the power purchase contract. There, where you have really close coverage of revenue to debt service is where you might be able to tap into long-term capital available to you from the utility industry, not at the variable rates but at a set rate for a period of time, which may make that project go. And that's where this bill might help out, by making that kind of capital accessible.

Senator HUMPHREY. Mr. Nicholson, let's try to get back to the situation as it now stands. When a company attempts to obtain cogeneration benefits at PURPA, what is FERC's role in that process?

Mr. NICHOLSON. When a company attempts to get the cogeneration benefits of PURPA, FERC has put up a set of rules. The only other involvement that comes to mind is one can file a document with FERC which says that you get to be qualifying. And there's a third thing in the regulations which says that there is some kind of a quandary after you get involved with the utility, and involved perhaps at the State level. Somewhere in there there's an appeal procedure.

I don't know if that has ever been exercised. I'm not sure of all the details of it.

Senator HUMPHREY. In your view, would this legislation affect that process in any way except to enlarge the field of potential applicants?

Mr. NICHOLSON. In my view, the involvement of the utility as we've stated or that might not have an impact on FERC, would have a mortifying impact on the private development because of the uncertainty, the possibilities of delay, the utility interest in obtaining ownership. Those are the kinds of things that even for well-financed companies it would tend to keep them from investing in this kind of thing because of the long-haul nature that could be involved on the regulatory side associated with the development.

Senator HUMPHREY. Have you found utilities cooperative? Or how would you rate their cooperativeness in the implementation of PURPA?

Mr. NICHOLSON. The general sense, and let me address it from two kinds of basics. One, the experience I've had at Potlatch and two, the experiences that have come through to us at the American Paper Institute.

At Potlatch, we operated in four States where we might build cogeneration units. Three of those States have not yet completed their activities. These are Arkansas, Pennsylvania, and Minnesota. In the State of Idaho which has been probably first in completing its endeavors, we did build one of these things. The only contract that we've been able to negotiate so far with the local utility is one for selling power as is——

Senator HUMPHREY. Have you found the utilities cooperative or uncooperative or where in between?

Mr. NICHOLSON. The survey that the American Paper Institute has taken has found a large number uncooperative in responses from the utilities.

Mr. JAMISON. I would say essentially the same thing. My company's experience has been very good. We have found good cooperation, and I cited the example that goes back to the cooperation of the extent of a sizable joint project. However, we also have heard members in the organization who have not had good experiences.

Senator HUMPHREY. That of course is always the case in any enterprise. But overall, are you in a position to give an overall rating or evaluation in the degree of cooperation by utilities in these PURPA programs?

Mr. JAMISON. I'm not prepared to speak on that for the association, however, I would certainly say from our own experience as Weyerhaeuser's experience with utilities, we have found cooperation to be very good.

Senator HUMPHREY. At least as far as Weyerhaeuser is concerned, cooperation has been very good.

Mr. Zimmer, can you tell us what experience your producer members have had with this respect?

Mr. ZIMMER. Mr. Chairman, it has been very much a case by case type matter which I think your question fully recognizes. I speak specifically to projects on a State by State type of basis. Projects in New Jersey have been proceeding on a pretty cooperative basis. Projects in New York have been proceeding under very difficult circumstances. The project we're working on particularly in Iowa, has been proceeding, I guess on a perspective of lack of interest really on the part of the electric utility.

The project engaged in in Massachusetts has been pretty much a neutral type of environment. And the final area is California, where the environment has been very positive and cooperative.

To summarize, I think there are some factors that really end up addressing that question and shaping the response. That it's a function of the State policies, the type of regulations and the requirements that it imposed under PURPA. Second, the nature of the utility management with whom you are dealing; and third, the presence or lack pf presence of capacity shortfalls in that service area. And I'd add fourth, maybe, the need for peaking power requirements, particularly. Those factors would shape the answer.

Senator **Humphrey**. Mr. Brown, have any of your studies encompassed this area? Are you in a position to evaluate the degree of cooperation the utilities have shown with PURPA?

Mr. **Brown**. We haven't completed any studies to date in this area. I would concur with my colleagues on this panel depending on a variety——

Mr. **Jamison**. Mr. Chairman, I'd like to refine my answer just a little bit. When I spoke of cooperation being relatively good, it was focusing principally on interconnection problems and willingness to sit down and talk about proposed projects. However, in one other aspect, I'd have to say that cooperation hasn't been all that good, and that is in regard to providing an avoided cost which is appropriate to the intent of PURPA section 210. We have found some reluctance to identify avoided costs that are high enough, in many cases to cause us to go into cogeneration projects, in some places where we would have an opportunity if the price was right. And there have been difficulties there.

Senator **Humphrey**. Ultimately you have some responsibility to the State PUC.

All right, gentlemen. Thank you very much. We appreciate your cooperation.

[Whereupon, at 12:25 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Committee Questions

Department of Energy
Washington, D.C. 20585

May 3, 1982

Ms. Marilyn Burkhardt
Counsel
Committee on Energy and Natural Resources
Washington, D.C. 20510

Dear Ms. Burkhardt:

Enclosed are responses requested by the minority staff following the April 19, 1982, hearing before the Senate Energy and Natural Resources Subcommittee on Energy Regulation. The subject of the hearing was S. 1885 and S. 1996, co-generation and electric utilities. The witness for the Department of Energy was J. Hunter Chiles.

The response to question 5 is currently being drafted and we hope to send it to you the week of May 9.

If you have any questions, please call Ingrid Nelson or Tom Pretorius of my staff on 252-4277. They will be happy to assist you.

Sincerely,

for Thomas H. Pretorius

Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosures

QUESTIONS FOR HEARING RECORD ON S. 1885 AND S. 1966

Department of Energy/Mr. Chiles

1. Please provide the Subcommittee with a list of states who have complied with the requirements of Sec. 309 of PURPA.
2. Please provide the Subcommittee with a list of states who have complied with the requirements of Sec. 116 of PURPA.
3. Page five of your prepared statement includes the following statements:

   > ..."I am concerned, however, that a few states have established rates that are higher than authorized by FERC's rules. ... It is DOE's hope that FERC, in its rules implementing Section 210 of PURPA, will be able to give more specific guidance to the states in order to minimize this subsidization problem."

   a. Is it the Administration's position that the minimum rate required to be paid qualifying facilities by PURPA should also be a maximum rate allowed by state commissions?

   b. If so, how would the maximum rate be imposed on the states?

   c. Does the Administration advocate establishing a maximum rate to be paid as a matter of Federal law, thus intruding even further than PURPA already does into what is generally a matter of state law?
4. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which would give the states discretion to grant utilities exemptions on a case-by-case basis. Please provide the Department of Energy's views on the amendment.
5. Please provide the Subcommittee with the draft legislative language to address the problems you identify on page 9 of your prepared testimony as "amenable to more direct solution at the Federal level."

Q. 1&2 Please provide the Subcommittee with a list of states who have complied with the requirements of Sec. 309 of PURPA. Please provide the Subcommittee with a list of states who have complied with the requirements of Sec. 116 of PURPA.

A. 1&2 The first two questions deal with listing the States that are in compliance with the requirements of Sections 309 and 116 of PURPA. The most recent data available is found in the May 1981 *PURPA Annual Report to Congress*, Volume 2, Chapter 2. The compliance status is shown for each covered utility. Summary statistics are found in Volume 1 of the *Annual Report*. The May 1981 *Report* reflects information current as of June 30, 1980.

As of that date, e.g., 17 months before the consideration process was statutorily required to be complete, the consideration process had begun in three quarters of the required cases. Final actions had been taken in over one third of the required cases. Based on the actions started by June 30, 1980, and upon information received informally, DOE believes that the great majority of States and utilities are in compliance with the consideration requirements of Titles 1 and III of PURPA. States and utilities will be submitting updated information to DOE in the next several months. A copy of the May 1981 *PURPA Annual Report to Congress* is enclosed.

Q. 3&3a Page five of your prepared statement includes the following statements: ... "I am concerned, however, that a few states have established rates that are higher than authorized by FERC's rules... It is DOE's hope that FERC, in its rules implementing Section 210 of PURPA, will be able to give significant guidance to the states in order to minimize this subsidization problem." Is it the Administration's position that the minimum rate required to be paid qualifying facilities by PURPA should also be a maximum rate allowed by state commissions?

A. 3(a) Section 210(b) of PURPA prohibits the FERC from requiring, on the authority of PURPA, a rate which exceeds "the incremental cost to the electric utility of alternative electric energy", i.e. a rate which exceeds the utility's "avoided costs". In essence, PURPA already establishes a maximum rate, but only for rates set under PURPA authority. The FERC rules carry out this mandate; but as the FERC correctly notes, State regulatory authorities (typically PUCs) may establish rates in excess of the full avoided cost level on the authority of State law. We do not advocate that a maximum rate be imposed on the States.

The point of my testimony is that we have noticed some cases where PUCs have set rates purportedly at the full avoided cost level but that in fact exceed that level because utility avoided costs have been incorrectly calculated. These rates, insofar as they exceed the full avoided cost level, create a subsidization of qualifying facilities (QFs) not authorized by Section 210 of PURPA.

We believe that it should be made clear that subsidizing rates are not authorized by PURPA. If such rates are to have a legal basis, it should be based on the laws of the State concerned. We believe that the FERC or the Congress can and should give more specific guidance to state regulators as to the appropriate way to calculate avoided costs. Specifically, "avoided cost" payments should be based upon the utility pursuing a capacity expansion plan calculated to minimize consumer costs over time. Payments to QFs for purchases should be calculated using the differential revenue requirements method or a similar method if the costs are going to be correctly calculated. If these steps are followed, PUCs will be able to avoid inadvertently subsidizing QFs. To this end, a clear statement of the intent of Congress, perhaps in the Statement of Managers or other place in the legislative history of S.1885, would be appropriate.

Q. 3(b) If so, how would the maximum rate be imposed on the states?

A. 3(b) As our answer to (a) demonstrates, DOE does not advocate that a maximum rate be imposed on the states.

Q. 3(c) Does the Administration advocate establishing a maximum rate to be paid as a matter of Federal law, thus intruding even further than PURPA already does into what is generally a matter of state law?

A. 3(c) As our answer to (a) demonstrates, DOE does not advocate that a maximum rate be imposed on the states.

Q. 4. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S.1885 which would give the states discretion to grant utilities exemptions on a case-by-case basis. Please provide the Department of Energy's views on the amendment.

A. 4 We understand the reasoning behind the suggestion that would leave the decision as to 100% utility ownership of QFs with the State regulatory commissions that have, under PURPA, the day-to-day responsibility for overseeing the QF-utility relationship. However, if it is appropriate for utilities to own 100% of QFs, and we believe it is appropriate if the competitive problems outlined in my testimony can be addressed, we see no reason why this should not be prescribed at the Federal level. States were not authorized to decide whether they would accept Section 210. It does not seem necessary to authorize states to decide whether utilities could become 100% owners of QFs. As I pointed out in my testimony, such a policy would be anticompetitive and would result in less QF electricity production at higher costs.

Q. 5 Please provide the Subcommittee with the draft legislative language to address the problems you identify on page 9 of your prepared testimony as "amenable to more direct solution at the Federal level."

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

IN REPLY REFER TO:

MAY 3 1982

Honorable Gordon J. Humphrey
Chairman, Subcommittee on
  Energy Regulation
Committee on Energy and
  Natural Resources
United States Senate
Washington, D. C. 20510

Dear Mr. Chairman:

During my testimony before the Subcommittee on Energy Regulation of the Senate Energy and Natural Resources Committee on April 19, 1982, I was asked whether utility participation in the benefits of the Public Utility Regulatory Policies Act of 1978 would affect small power producers differently from the way it would affect cogenerators. I am now submitting that information for the record (Enclosure A) together with the answers to the supplemental questions in your letter of April 28, 1982 (Enclosure B).

I hope that you find the enclosed information helpful. If I may be of any further assistance, please do not hesitate to call on me.

Sincerely,

C. M. Butler III
Chairman

Enclosures

A. 5 Regarding question 5, we are currently drafting language that could be used to alleviate legislatively or administratively at the Federal level the problems we have identified. We hope to be able to provide this to you by the week of May 9.

QUESTION SUBMITTED DURING HEARING

Question:

> Do you feel that utility participation in the benefits of PURPA would affect small power producers differently than it would cogenerators?

Answer:

There are reasons to expect differences, not only between small power producers and cogenerators, but also among different technologies in both categories. Among potential small power production energy sources, wind or geothermal energy can be developed by either a utility or by some other person, and there is no reason to expect a different technical design to result from ownership differences. For other small power production opportunities, on the other hand, certain types of owners may have an advantage for reasons quite apart from PURPA. A municipal solid waste-fired facility requires the cooperation of the authority responsibile for garbage collection. Municipal utilities might be ideal for owning such a project. 1/ Under the Federal Power Act, preference in licensing non-Federal hydro development must be given to public power developers. Allowing such persons the PURPA benefits may facilitate development.

1/ The question of whether a municipality that also operates a utility can own a qualifying facility is unresolved. Arguably, there is no restriction as long as the utility itself does not own the facility.

Cogeneration differs from small power production in that more than electricity must be produced. Cogenerators produce thermal energy (typically steam) that must be used for some industrial, commercial, heating, or cooling purpose. Unless engaged in a district heating project, utilities have no use for such thermal energy -- a buyer must be found.

A utility cogenerator's need to market steam could create several kinds of problems that have no direct counterpart where the utility owns a small power production facility:

- In many states, steam sales are regulated by state commissions in a traditional "cost plus reasonable rate of return" manner. Thus, through regulation of steam sales, state authorities might essentially tax away the profits of the unregulated electric generation.
- Steam cannot be transported economically for long distances (more than a few miles). Thus, cogeneration facilities must be located in close proximity to the industrial steam load. On the other hand, some industrial companies are reluctant to allow outside parties access to their plants. The design of a utility-owned cogeneration facility may, therefore, be more complex.

° Many industrial companies do not wish to "lose control" over their source of steam. For many industrial processes -- particularly in the chemical industry -- interruption of steam flow can result in costly loss of production of even destruction of equipment. Such companies would be willing to buy steam only if back-up boilers were available. Such boilers are usually available at an existing plant that decides that utility cogenerated steam is more economical. At a new plant, however, new boilers would have to be constructed, and the industrial may wish to do the cogeneration itself or else not participate in any cogeneration activities.

A more positive aspect of utility ownership of cogeneration facilities has been raised in a DOE-funded study of the potential for cogeneration development. 2/ The study suggests that allowing utilities the full PURPA benefits will encourage an additional 4,000 megawatts of cogeneration capacity by 1990. Although the extra development is due to several independent effects, one major reason is found to be a preference by utilities

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2/ The Potential for Industrial Cogeneration Development by 1990, Resource Planning Associates, Inc., July 31, 1981.

for cogeneration technologies with high electrical-to-thermal ratios. An industrial customer may be expected to install a steam turbine cogeneration unit that produces only a small output of electricity while meeting the need for steam. An electric utility, however, may install a combined-cycle cogeneration facility that produces from four to 20 times the electrical output per unit of steam.

Utilities may also be more familiar with the operation of coal-fired facilities than most industrials are. Utility-owned cogeneration facilities may, therefore, be more likely to be coal-fired.

ADDITIONAL QUESTIONS SUBMITTED BY THE MAJORITY

Question No. 1(a):

> Does the Solicitor General intend to file a petition for certiorari with the U.S. Supreme Court in the American Electric Power Service Corporation v. FERC, No. 80-1789 (D.C. Cir. Jan. 22, 1982) case?

Answer 1(a):

Commission attorneys are presently preparing a recommended petition for a writ of certiorari in the American Electric Power case to present to the Solicitor General's office. As yet, so far as we know, the Solicitor General has not decided whether to file such a petition.

Question No. 1(b):

> If so, when would the Supreme Court be likely to decide whether to grant certiorari in the American Electric Power case?

Answer 1(b):

If a petition for a writ of certiorari is filed, the Court would decide whether to grant certiorari when its October 1982 term begins.

Question No. 1(c):

> If the Supreme Court does not grant certiorari, when would the Court be likely to issue a decision on the merits in the American Electric Power case?

Answer 1(c):

If certiorari is granted, a decision on the merits would be likely to issue before the October 1982 term ends in early summer 1983.

Question No. 1(d):

> Does the Commission intend to defer a rulemaking on interconnection and avoided cost until all court proceedings in the American Electric Power case are concluded? When do you estimate that a new rulemaking would commence assuming each of the following circumstances:
>
> (1) The Solicitor General does not file a petition for certiorari;
>
> (2) the Supreme Court denies certiorari;
>
> (3) the Supreme Court upholds the Circuit Court's opinion; or
>
> (4) the Supreme Court decides that the Circuit Court applied the wrong standard of review and remands the case to the Circuit Court.

Answer 1(d):

The Commission currently has no plans to reexamine or revise its rules which implement the interconnection or ratemaking authority under section 210 of PURPA or to establish interconnection procedures under sections 210 and 212 of the Federal Power Act.

If the Commission were to determine that any additional cogeneration and small power production rulemakings are desirable, such rulemakings could be undertaken during the pendency of the American Electric Power (AEP) litigation, although, as your question implies, a rulemaking would most likely commence after the mandate of the Circuit Court issues. The dates on which the AEP case could be resolved in a manner which would require further Commission action are:

Answer 1(d)(1):

After July 8, 1982, if the Solicitor does not file for certiorari;

Answer 1(d)(2):

October or November, if the Supreme Court denies certiorari;

Answer 1(d)(3):

Late spring of 1983, if the Supreme Court decides the case and upholds the decision; or

Answer 1(d)(4):

As late as the late winter or spring of 1984, if the case is remanded for further review at the Circuit Court level using an appropriate standard of review.

Question No. 2:

In the American Electric Power decision, the Court stated that the FERC must balance the interests of cogenerators, consumers, and the public interest in order to promulgate a proper rule on the rates which qualifying facilities can charge a utility for power.

Question No. 2(a):

What specific factual record would the FERC have to develop in order to comply with the Court's decision?

Answer 2(a):

With respect to the validity of the Commission's interconnection rule, the state of the factual record is not at issue. The Circuit Court vacated the rule because it did not comply with what the court perceived as a compelling reading of section 210 of PURPA, not because the Commission failed to explain adequately its decision to order all utilities to interconnect.

With respect to the validity of the full avoided cost standard for rates for purchase from qualifying facilities, the central issue is whether the Commission's order reflects an adequate record and contains a sufficient explanation of the rule's compliance with statutory standards.

The standard of review applied in the AEP case is important to any judgment of what will be required for any new rule to pass judicial muster next time. The Circuit Court opinion does not delineate precisely the standard of review which it used. On one hand, a narrow reading of the AEP case suggests an arbitrary and capricious standard of review. The court may only have been concerned that the Commission failed to consider all of the relevant factors specified by Congress in section 210 of PURPA for setting the cogeneration rates, i.e., the encouragement of cogenerators, the impact upon electric utility consumers, and the public interest.

On the other hand, the AEP opinion intimates that a higher standard of review, perhaps even the "substantial evidence" test, is being employed by the court. Judge Wilkey relies "generally" upon Public Systems v. FERC, 606 F.2d 973 (D.C. Cir. 1979), in which the same Circuit Court applied the "substantial evidence" standard of review to the Commission's tax normalization regulations for electric utilities. Under that decision, factually-based decisions by an agency are potentially subject to a review approximating the "substantial evidence" test. The Public Systems court nevertheless acknowledged that a rule is otherwise reviewable according to a standard closer to "arbitrary and capricious" if "[the rule] represents a policy decision without direct factual predicate." It is unclear how important the Public Systems case is to the holding in the AEP case. Several passages in the decision suggest dissatisfaction with the factual support for the Commission's conclusions, thereby implying that the quantum of evidence is the problem, not just a failure to meet statutory requirements.

If the Court prescribes an arbitrary and capricious test, compliance with the AEP case may not require development of a new or different factual record for a further rulemaking under section 210 of PURPA. Rather, further explanation of how the rule fulfills statutory requirements would suffice.

On the other hand, a higher standard of review may make it incumbent upon the Commission to provide explicit and detailed cost of service studies of several subject areas, in order to ascertain at which level the avoided cost rate may be set without impairing the development of cogeneration or small power production and thereby acting contrary to the statutory purpose. Judge Wilkey suggested other factors for the Commission to consider, such as the impact on or from market forces if there is a lower than full avoided cost rate, and the possible existence of actual monopsony power among electric utilities in the market place.

Question 2(b):

> Please estimate the length of time it would take the Commission to develop such a factual record and to promulgate a rule which would meet the requirements of the American Electric Power decision?

Answer 2(b):

The time required for the Commission to develop a factual record in conformance with the AEP decision would also be affected by the standard of review. The factual record for the existing rule, including an environmental impact statement, took nearly two years to complete. If the Commission were to undertake extensive cost of service studies as a basis for setting a specific avoided cost rate, or a range of such rates, the task arguably could require one or two years. If it were determined that such studies were not necessary, the Commission could reexamine the existing record in light of the AEP decision and the statute and further explain the basis of the existing, or any revised rule. A rulemaking on the rate for purchase would require a minimum of six months to complete. A rulemaking to provide interconnection procedures would probably require less time.

Question No. 3:

> How has the development of cogeneration and small power production been affected by the American Electric Power case?

Answer 3:

At the present time there has been no discernible effect on the number of "qualifying facility" filings received by the Commission. In the fiscal quarter immediately prior to the AEP decision, first quarter FY 1982, the Commission received 43 filings -- either giving notice of compliance with the Commission's rules for qualifying facilities or requesting

Commission certification of qualifying status. In the second quarter of FY 1982, during which the AEP decision was issued, 61 filings were received. 1/ Thus, the level of activity directly observed by the Commission has actually increased.

There are three reasons for the apparent lack of immediate impact. First, the filings that are now being received by the Commission may represent facilities that were planned prior to the AEP decision. In effect, the unavoidable lag in the process of facility development may postpone any adverse impact until the future. The filings we are seeing now were "already in the pipeline." The ultimate impact of the AEP decision is made all the more uncertain by this lag effect.

A second reason for the lack of an immediate impact probably lies with the actions of a number of state agencies. In several states with a large potential for cogeneration and small power production, state authorities have asserted an independent right to establish rates, and in some instances, order interconnections. The New York State legislature, for example, has enacted a "mini-PURPA" that sets the rate for utility purchases of electricity from certain cogenerators

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1/ Of the 43 filings received in the first quarter of FY 1982, two were incomplete or outside the scope of cogeneration and small power production. In the second quarter, three of the 61 filings received are similarly incomplete or inconsistent with the PURPA program. These filings are not included in the quarterly summaries of qualifying facilities prepared by the FERC staff.

and small power producers at 6 cents per kilowatt-hour. The Florida Public Service Commission has recently ordered Florida Power and Light to interconnect with a small power producer. In California, the Public Utilities Commission has announced that its order implementing FERC's Order No. 69 is not invalidated by the AEP decision.

Such state actions probably have influenced some cogenerators and small power producers to press on with their development plans. Ultimately, however, such independent state actions may be overturned in the courts. I have been informed that a number of persons expect to challenge states' authority to order interconnections and to set rates for utility purchases of power from qualifying facilities.

Finally, it must be remembered that the Court of Appeals order vacating and remanding portions of the Commission's rules have been stayed. Thus, the FERC's own rules on interconnection and avoided cost pricing have remained in effect for the time being. Any direct impact on cogenerators and small power producers will be likely only after the court's order is mandated.

Apart from the evident lack of any impact of the AEP decision at the level of the FERC, discussion with staff members of the state regulatory authorities has revealed a slight slowdown in activity. In California, projecters are going forward, but at a somewhat slower pace. It is not clear, however, whether the slowdown is due to the AEP decision or is a result of the economic recession.

Question No. 4:

> What impact on the development of cogeneration and small power production can be expected if substantial legal questions regarding FERC rules on interconnection and avoided cost are not resolved for several years?

Answer 4:

Any impact of such protracted uncertainty can only be negative, but the extent of the negative impact is unclear at this time. Much depends upon the future actions of the states and utility purchases of power; the impact of uncertainty at the federal level will be greatly reduced. Moreover, many utilities are likely to offer to interconnect without going through a hearing at the FERC pursuant to sections 210 and 212 of the Federal Power Act (provided, of course, that the cogenerator or small power producer offers to pay for the interconnection). Many cogenerators are also likely to reach a negotiated settlement of the rate issue, and enter into a private contract. Substantial legal questions regarding the FERC rules may affect these negotiations, but if state regulatory authorities agree to review the contracts and guarantee passthrough of the utility's costs, there is reason to expect that many of the larger cogeneration projects will not be deterred.

Cogenerators and small power producers will be affected differently by an extended period of uncertainty. Cogenerators typically are industrial corporations with a sizable demand for electricity. The Commission staff has found, through informal discussions, that many cogenerators are planning on using their electrical output directly, rather than selling it to the utility company at avoided cost. In most regions of the country, the avoided cost purchase rates are lower than the retail sales for electric service. 2/ A cogenerator thus is economically better off utilizing cogeneration as a conservation measure -- reducing demand for utility power -- rather than offering power for sale. A study of cogeneration potential, sponsored by DOE, projected 6,300 megawatts of new cogeneration development under a "no excess" power assumption. 3/ This contrasts with a base case projection of 12,800 megawatts developed with reasonable buyback rates. The smaller projected cogeneration capacity under the no excess scenario is due principally to facilities adopting technologies with low

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2/ New England, upstate New York, and much of the West Coast are the exceptions.

3/ The Potential for Industrial Cogeneration Development by 1990, Resource Planning Associates, Inc., July 31, 1981.

electricity-to-steam ratios (such as steam turbines), rather than to cogeneration opportunities being abandoned.

For small power producers, the impact of an extended period of uncertainty is likely to be more severe. Small power producers have little or no on-site electrical demand. The electric utility is the only market for the power. For this reason, both the interconnection and the avoided cost issue loom large in evaluating the feasibility of a project.

Certain small power production facilities, such as wind and hydro, are likely to be small in size. Such small facilities have less bargaining power in negotiations with the utility. Moreover, wind and hydro facilities are often located in remote sites. This tends to make interconnections more expensive.

Other technologies, such as municipal solid waste-fired plants and geothermal facilities, are larger in size. Not only will the negotiating position of a larger facility (50 to 80 megawatts) be better, but interconnection costs will probably be less for municipal waste and geothermal facilities. The municipal waste facilities will be located near population centers with established transmission and distribution networks. Geothermal facilities will be located in geothermal fields at which other projects are likely.

If substantial legal questions remain open for a period of several years, the principal losers are likely to be wind, hydro, and advanced, high electricity-to-thermal ratio cogeneration facilities.

Question No. 5:

> In the American Electric Power case, the Court stated that the FERC could adopt streamlined procedures for interconnections which would not impose substantial administrative burdens on qualifying facilities seeking interconnection. In view of the procedural and substantive requirements of sections 210, 211 and 212 of the Federal Power Act, please describe the procedures with which a qualifying facility must comply in order to interconnect with an electric utility and how the FERC would streamline such procedures?

Answer 5:

Section 210 of the Federal Power Act was added by section 202 of PURPA. It states, in pertinent part, that the Commission may order an interconnection between a utility and a qualifying facility after:

> (1) issu[ing] notice. . .
>
> (2) afford[ing] an opportunity for an evidentiary hearing, and
>
> (3) mak[ing] a determination with respect to the matters referred to in subsection (c) of this section [regarding the

> public interest, conservation of energy or capital, efficient use of facilities and resources, improving the utility system's reliability and certain procedural requirements.] 16 U.S.C. § 824i.

Thus, if a decision were made that the Commission must follow the procedures in sections 210 and 212, a qualifying facility which intends to sell electric energy to an electric utility could be required by that electric utility to come to the Commission for an order requiring interconnection. Before the Commission could order interconnection under section 210 of the Federal Power Act (FPA), however, it would be required to follow the procedures set out in section 212 of the FPA. Section 212 requires, inter alia, that the Commission find that such order:

(1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility or qualifying facility,

(2) will not place an undue burden on an electric utility or qualifying facility,

(3) will not unreasonably impair the reliability of any electric utility affected by the order, and

(4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

Furthermore, an order could not be issued by the Commission unless the qualifying facility is willing and able to reimburse the electric utility for the costs of interconnection.

Because an "evidentiary hearing" is required by section 210 of the FPA, all parties to an interconnection proceeding may be required to follow the Commission's Rules of Practice and Procedure for evidentiary hearings. This includes a hearing before an Administrative Law Judge which would require the filing of initial briefs, pre-filed testimony, and reply briefs. Depositions could be required as well as data requests between the parties. Typically, an initial decision is issued by an Administrative Law Judge following the hearing. Even if an Administrative Law Judge is not required, however, the Commission would have to make the requisite findings under sections 210 and 212 of the FPA. After a decision is made by an Administrative Law Judge, the Commission reviews the decision _de novo_. A party to the proceeding may petition for rehearing of the Commission's final decision. Moreover, a final Commission decision may be appealed to a Federal Court for further review. This entire process could take up to 2-3 years to resolve all material factual issues, if expedited procedures were not adopted.

The Court suggested that the Commission could streamline this procedure. It is possible that this could be done. However, addressing the feasibility of such procedures would require substantial legal analysis which has not been done. I have no plans to direct the undertaking of this work until I have a definitive idea of where litigation of the AEP case is going.

Question No. 6:

> Please clarify for the record whether or not it will be necessary for the Commission to take another vote in order to authorize the filing of a petition for certiorari in the Supreme Court in the American Electric Power case.

Answer 6:

The Commission has already authorized its attorneys to seek a writ of certiorari in the American Electric Power case.

Question No. 7:

> Please provide the Subcommittee with a list of the qualifying cogeneration and small power production facilities certified since enactment of PURPA (excluding preliminary permits for the latter). Please indicate what company or companies own the facility, the date the Commission received the application in each case, and the date on which it was approved.

Answer:

Under the Commission's rules, a cogeneration or small power production facility is a qualifying facility if it meets the criteria of the rules. All qualifying facilities which declare themselves to be such and seek the benefits available to qualifying facilities are directed to file an information notice of qualifying status with the Commission. Such individual determinations that the criteria are met are called self-qualifications.

Utilities, State regulatory authorities and others may challenge the correctness of self-qualifications and dispute the eligibility of a facility for the benefits sought. To resolve or forestall such situations, the rules provide a procedure for obtaining Commission certification of a facility's qualifying status, which is granted through a formal order.

Typically, certification is sought where a substantial investment is involved even though qualifying status appears evident, or where there is doubt of qualifying status because of uncertain interpretation of the Commission's rules. Approximately 60 percent of the filings in regard to qualifying status are for certification, indicating that a large percentage of the wind and small hydropower generators are not filing notices of self-qualification. A possible explanation is that such facilities have concluded satisfactory arrangements with the utilities and see no need to claim qualifying status.

A list of Commission-certified cogeneration and small power production facilities (Appendix A), and the most recent Commission quarterly report on qualifying small power production and cogeneration facility filings (Appendix B), are attached to these answers. The latter document includes, for the period that it covers, both applications for Commission certification and notices of qualifying status.

Question No. 8:

> Is FERC seeking to appeal the decision of the D.C. Circuit Court in the AEP v. FERC case to the Supreme Court? What is the position of the Justice Department on appealing the case?

Answer 8:

Commission attorneys are presently preparing a recommended petition for a writ of certiorari in the American Electric Power case to present to the Solicitor General's office. As yet, so far as we know, the Solicitor General has not decided whether to file such a petition.

If a petition for a writ of certiorari is filed, the Court would decide whether to grant certiorari when its October 1982 term begins.

If certiorari is granted, a decision on the merits would be likely to issue before the October 1982 term ends in early summer 1983.

Question No. 9:

> Has FERC considered reopening the cogeneration rulemaking proceeding to amend the rules vacated by the Court? Under what circumstances would this be desirable?

Answer 9:

Reopening the rulemaking under section 210 of PURPA is an option which has been considered by the Commission. Certainly, the Commission would revisit the existing rules or undertake a new rule if the Circuit Court's mandate were to issue. Pending resolution of the AEP case on appeal, however, there are questions about the advisability of expending Commission resources on changes to the cogeneration program until it is finally resolved what the Commission's obligations under that case are. I have no plans to recommend to the Commission that it undertake this task until the litigation phase of the AEP case is terminated.

Question No. 10:

An interview with you was conducted by the newsletter, Inside FERC, and published on January 25, 1982. This is what the newsletter printed:

"--The constitutionality of PURPA. Butler said that if he were sitting on the Supreme Court,

> 'I would rule against the government in this case.'

From his perspective on constitutional law, the question of forcing states to cooperate with the goals of federal law is closer in the case of NGPA, but

> 'I would probably go the same way'

How much confidence should the Committee have in your enthusiasm for the cogeneration and small power production program contemplated in PURPA?

Answer 10:

My views of the constitutional issues of PURPA are essentially structural and have nothing to do with any attitude or policy views toward cogeneration and small power production. That attitude and those views are generally favorable. More importantly, I intend to do what I can to see that all of the Commission's responsibilities are adequately discharged. My criticism of the Natural Gas Policy Act is more substantive, but that does not mean that I will not enforce it.

Appendix A
Page 1 of 4

Commission Certified Qualifying Cogeneration and Small Power Production Facilities

Docket No.	Applicant Name	Date Filed	Date Certification Granted	Max. Electric Capacity (kW)	Small Power(SP) /Cogeneration(C)
QF 80-1	Lawrence Hydroelectric Associates	3/19/80	5/30/80	15,000	SP
80-2	Ottumwa Water Works and Hydroelectric Plant	4/1/80	6/18/80	3,000	SP
80-3	Buffalo Color Corp.	4/14/80	6/26/80	5,000	C
80-6	Power Systems Engineering and Great Lakes Carbon	5/20/80	8/8/80	75,000	C
80-7	S. San Joaquin Irr. District and Oakdale Irrigation District	6/1/80	9/17/80	2,300	SP
80-8	Twin Falls Canal Co.	6/5/80	9/2/80	8,921	SP
80-9	Brooks City Dairy	5/28/80	9/11/80	50	SP
80-11	Hunt Wesson Foods	6/11/80	9/17/80	1,000	C
80-12	Furniture Division of Singer Co.	7/2/80	9/11/80	400	C
80-13	Windfarms, Ltd.	7/11/80	10/3/80	76,000	SP
80-17	Vermont Marble Co.	8/6/80	1/28/81	18,450	SP
80-19	Cranston Print Works Co.	8/26/80	10/28/80	3,000	C
80-20	Hoffmann-LaRoche Diesel Cogeneration System	8/26/80	10/26/81	23,300	C
80-21	French Paper Co.	8/25/80	10/28/80	1,400	SP
80-22	Republic Geothermal	9/9/80	4/27/81	76,000	SP
80-23	Union Camp Corp.	9/8/80	12/15/80	161,000	C
80-26	Argonne National Lab	9/11/80	12/12/80	19,500	C
80-27	Quaker Oats Co.	9/25/80	12/18/80	1,500	C
80-28	Stieren Farms	9/26/80	12/21/81	500	SP
81-2	Merced Irrigation District	10/3/80	1/2/81	2,800	SP
81-4	Dickerson Lumber Co.	10/14/80	1/28/81	1,000	SP
81-5	John E. Eckland	11/12/80	2/12/81	4	SP
81-6	Canners Steam Co.	11/12/80	2/26/81	2,600	C
81-7	Occidental Geothermal	11/21/80	12/11/81	80,000	SP
81-8	Sea World	12/18/80	9/4/81	1,260	C
81-8-001	Sea World(modification)	11/13/81	2/11/82	690 added	C
81-12	American McGaw, Division of American Hospital	1/19/81	3/25/81	2,800	C
81-13	EG&G, Inc.	1/21/81	7/23/81	580,000	C

Docket No.	Applicant Name	Date Filed	Date Certification Granted	Max. Electric Capacity (kW)	Small Power(SP) /Cogeneration(C)
81-14	University of Massachusetts Medical Center	2/2/81	6/4/81	5,000	C
81-17	Norton Co.	2/18/81	7/27/81	6,000	C
81-18	Trenton Cogeneration Development Corp.	3/2/81	6/1/81	12,000	C
81-23	New England Alternate Fuels	4/6/81	9/16/81	2,500	SP
81-27	Koppers	4/21/81	8/26/81	750	C
81-28	Clark University	4/27/81	7/27/81	1,800	C
81-29	H.M. Browning	5/6/81	8/26/81	4	SP
81-30	ARCO Polymers	4/30/81	8/10/81	31,500	C
81-31	J.A. Miller	5/8/81	8/26/81	10	SP
81-32	Alabama River Pulp Co.	5/12/81	8/26/81	48,000	C
81-34	Hach Energy Systems, Inc.	6/2/81	8/31/81	10	SP
81-35	Hudson Lumber Co.	6/1/81	9/25/81	5,069	SP
81-36	Watson Biogas Systems			1,348	C
81-38	McEachern Farms	6/4/81	11/6/81	1,700	SP
81-39	George Eldridge & Son, Inc.	6/19/81	9/16/81	25	SP
81-41	Walter Poock	6/22/81	9/16/81	35	SP
81-42	John Root	7/7/81	9/25/81	10	SP
81-43	Lyle Tempus	7/7/81	10/19/81	10	SP
81-44	Dr. J.C. Comstock	7/7/81	9/25/81	10	SP
81-48	M. Grundmeier	6/2/81	8/31/81	10	SP
81-50	Fayette Manufacturing Corp.	7/16/81	10/9/81	10	SP
81-52	Arcata Lumber	7/28/81	10/20/81	22,500	SP
81-56	Burlington Environmental Management Services	7/30/81	10/20/81	10,000	SP
81-57	City of Tampa	8/10/81	11/6/81	10,000	SP
81-59	USS AgriChemicals 1/	8/12/81	10/29/81	45,000	SP
81-61	American Gas Recovery Co. Kramer Landfill	8/27/81	11/25/81	32,000	C
81-63	American Gas Recovery Co. Harris Landfill	9/2/81	12/4/81	10,000	SP
81-64	Caterpillar Tractor Co.	9/1/81	12/4/81	10,000	SP
81-65	Pequod Power & Light 2/	9/4/81	12/31/81	2,070	C
		9/9/81	12/10/81	7,500	SP

1/ Jointly owned with W.R. Grace and Co.
2/ Joint venture by the March Co. and Pequod Assoc.

Docket No.	Applicant Name	Date Filed	Date Certification Granted	Max. Electric Capacity (kW)	Small Power(SP) /Cogeneration(C)
81-67-001	General Electric Credit Corp. 3/	10/28/81	1/26/82	46,700	C
81-68	New England Alternate Fuels Brattleboro Sanitary Landfill	9/23/81	12/4/81	325	SP
81-69	Occidental Chemical Co. 4/	9/24/81	12/24/81	15,000	C
81-70	Memphis Hardwood Flooring Co.	9/28/81	12/24/81	1,268	C
81-71	Memphis Hardwood Flooring Co.	9/28/81	12/24/81	527	C
82-2	John Deere Component Works	10/5/81	12/31/81	14,500	C
82-4	Huntsville Microcircuits, Inc.	10/15/81	12/24/81	80	SP
82-5	Republic Geothermal	10/20/81	12/24/81	49,000	SP
82-7	Travenol Lab. Inc.	10/14/81	12/24/81	400	C
82-10	American Gas Recovery Corp. Delta Altoona Sanitary Landfill	11/2/81	1/8/82	10,000	SP
82-12	Getty Synthetic Fuels, Inc.	11/4/81	1/8/82	5,700	SP
82-15	Gorge Energy Corp.	11/9/81	1/8/82	5,000	SP
82-20	Imotek, Inc. 5/	11/18/81	2/16/82	8,500	C
82-22	Richard Walker	11/17/81	2/11/82	10	SP
82-23	Vulcan Materials Co.	11/25/81	3/16/82	33,730	C
82-24	Pacific Telephone & Telegraph Co.	11/27/81	2/16/82	5,500	C
82-25	Stone Container Corp.	11/30/81	2/11/82	16,500	C
82-34	ITT Continental Baking Co.	12/21/81	3/12/82	894	C
82-38-001	Robert Hetzler	1/18/82	4/8/82	20	SP
82-44	E.L. Copley III	12/17/81	3/12/82	50	SP
82-47	Rockfish Corp.	1/11/82	4/9/82	400	SP
82-54	North Canal Waterworks 6/	1/21/82	4/19/82	2,520	SP
82-59	Community Linen Rental Service	1/25/82	4/8/82	500	C
82-62	Westfir Energy Co.	1/26/82	4/28/82 7/	4,500	SP
82-63	Westfir Energy Co.	1/26/82	4/28/82 8/	7,500	SP
82-64	Chevron USA Inc.	1/25/82	4/8/82	4,275	C
82-65	Chevron USA Inc.	1/25/82	4/14/82	10,000	C
82-66	Chevron USA Inc.	1/25/82	4/14/82	7,500	C
82-67	Chevron USA Inc.	1/25/82	4/22/82	2,500	C
82-68	Hercules, Inc. Forster Plant	1/28/82	4/8/82	600	C

3/ Operated by Scott Paper Co.

4/ Leased from Bank of America

5/ Lessee under leveraged lease financing arrangement.

6/ Lessee and operator. Facility owned in part by Rowland Industries, in part by the Essex Company.

7/ Approximate date.

8/ Approximate date.

Docket No.	Applicant Name	Date Filed	Date Certification Granted	Max. Electric Capacity (kW)	Small Power(SP) /Cogeneration(C)
82-74	Massachusets Hydro Assn. 9/	2/9/82	4/19/82	500	SP
82-75	Wheelabrator-Frye Inc.	2/12/82	4/23/82	55,000	SP
82-79	Steamco, Inc.	2/19/82	4/23/82	1,600	C
82-82	Urban Refergy Skokie Partnership	2/23/82	4/23/82	5,500	SP
82-83	Hooker Chemicals & Plastics Corp.	2/25/81	4/23/82	42,400	C

9/ Lessee and operator. Facility owned by Atlantic Associates.

QUARTERLY REPORT ON QUALIFYING SMALL POWER PRODUCTION AND COGENERATION FACILITY FILINGS, April 1, 1982

During the period January 1, 1982 to April 1, 1982, 58 filings for qualifying facilities were made under the Commission's rules for cogeneration and small power production facilities. Twenty-nine filings were applications for certification of qualifying status and twenty-nine were notices of qualifying status.

Of the 201 filings made since April 1980, 113 have been applications for certification. Orders have been issued certifying 76 of the facilities; 3 facilities have been denied certification. Of the remaining 34 applications, 26 were filed in complete form less than 90 days before April 1, 1982 and are still under review, and 5 have not yet been filed in complete form. The other 3 applications have been tolled (Commission suspension of automatic grant at 90 days), 1 at the applicant's request and 2 because petitions or protests have been filed regarding certification of the facility and/or because the application raises a special issue requiring Commission evaluation.

QUARTERLY SUMMARY Second Quarter, FY 1982

		(no. filings)	capacity in KW
Small Power			
	Small Hydro	(9)	8,828
	Wind	(15)	92,577
	Biomass	(8)	127,950
	Waste	(1)	450
	Geothermal	(1)	13,500
	Solar	(1)	100
	Other	(0)	--
	TOTAL	(35)	243,405
Cogeneration			
	Oil and Gas	(16)	390,750
	Other	(7)	666,139
	TOTAL	(23)	1,056,889
TOTAL Second Quarter FY 1982		(58)	1,300,294

COGENERATION AND SMALL POWER PRODUCTION FACILITY FILINGS

Docketed with the FERC as of April 1, 1982*
Aggregated by Census Region

Abbreviations and explanations for the following tables:

Fil Type (Filing Type)

C: Application for Certification
N: Self-qualifying Notice

Type Fac (Type of Facility)

SP: Small power production facility
- H: Hydroelectric
- W: Wind
-SO: Solar
- B: Biomass
-WA: Waste
- G: Geothermal
- O: Other SP type

C: Cogeneration facility
-S: Steam turbine
-CT: Combustion / gas turbine / Combined cycle
-D: Diesel engine
-DF: Dual fuel engine
-SI: Spark ignition

Cog Fuel (Cogeneration Fuel Source)

CO: Coal
F06: #6 oil
F02: Diesel oil
NG: Natural gas, Interruptible NG with F06 or F02 as backup
BIO: Biomass
NUC: Nuclear facility
O: Other Cog. type

Cert Date (Date QF certified by the FERC)

Start Instal (Date installation began/will begin on QF)

Notes

Tolled: FERC 90 day action time limit extended by Commission order

*NOTE: The FERC does not review self-qualifying facility notices and has not completed review of all listed applications for certification. See coded information for each filing.

TABLE I

FILING TYPE [1]
(no. filings) and capacity in KW

Filing Type	Certification	Notice	Total
FY 1980	(23) 545,631	(7) 168,380	(30) 714,011
FY 1981	(43) 955,630	(26) 332,471	(69) 1,288,101
FY 1982, To date	(47) 1,195,289	(55) 1,057,434	(102) 2,252,723 [2]
Total to date	(113) 2,696,550	(88) 1,558,285	(201) 4,254,835 [3]

1/ Dockets No. QF81-67-001, QF82-38-001, QF82-102-001 and QF82-103-001 are applications for 'certification' made for facilities for which 'notice' of self-qualification had been previously submitted. To avoid duplication of data on these facilities, all information is entered for the 'notice' filing only. The applications for certification are entered in regional tables, however.

2/ Dockets No. QF81-51-000 and QF82-40-000 were included in data in the January 1, 1982 Quarterly Report but have been deleted from data in this report. Additionally, Dockets No. QF82-40-001 QF82-70-000 and QF 82-78-000 are not included in this report.

3/ Dockets No. QF80-4-000, QF80-25-000 and QF82-6-000 were included in aggregate data for "filing type" but were not included in the remainder of Table I or in Tables II, III and IV because they were denied certification by the FERC.

TABLE II

AGE CATEGORY: NEW / EXISTING 1/
(no. filings) and capacity in KW

New/Existing on 11/9/78.	New	Existing	Total
FY 1980	(17.5) 392,579	(10.5) 290,612	(28) 683,191
FY 1981	(60) 1,175,875	(9) 112,226	(69) 1,288,101
FY 1982, To Date	(88) 1,377,764	(15) 874,159	(101) 2,251,923 2/
Total to date	(163.5) 2,946,218	(34.5) 1,276,997	(198) 4,223,215 3/

1/ Facilities whose construction began prior to November 9, 1978, the date of PURPA enactment, are not necessarily entitled to section 210 rates.

2/ See Table I, footnote 2/.

3/ See Table I, footnote 3/.

TABLE III

COGENERATION FACILITIES
(no. filings) and capacity in KW

FUEL	FY 1980			FY 1981			FY 1982 To Date			TOTAL to date
	New	Existing	Total	New	Existing	Total	New	Existing	Total	
Coal	(3) 88,000	(0) —	(3) 88,000	(2) 611,500	(1) 23,000	(3) 634,500	(2) 26,600	(2) 28,989	(4) 55,589	(10) 778,089
Nat.Gas	(1) 1,000	(3) 146,250	(4) 146,250	(7) 73,789	(2) 11,000	(9) 84,789	(20) 354,502	(6) 755,000	(26) 1,109,502	(41) 1,340,541
Biomass	(1) 400	(0) --	(1) 400	(4) 49,325	(2) 49,268	(6) 98,593	(6) 112,175	(2) 39,375	(8) 171,750	(15) 270,743
Waste	(1) 75,000	(0) —	(1) 75,000	(3) 60,280	(0) --	(3) 60,280	(1) 8,000	(0) —	(1) 8,000	(5) 143,280
FOG/FOZ	(1) 23,300	(1) 5,000	(2) 28,300	(0) --	(0) —	(0) --	(2) 4,300	(0) —	(2) 4,300	(4) 32,600
Other	(0) --	(2) 105,500	(2) 1/ 105,500	(1) 1,800	(0) —	(1) 1,800	(1) 560,000	(1) 3,675	(2) 563,675	(5) 670,975
Total CF	(7) 187,700	(6) 255,750	(12) 1/ 443,450	(17) 796,694	(5) 83,268	(22) 879,962	(30) 1,065,577	(11) 847,239	(41) 1,912,816	(75) 1/ 3,236,228

1/ QF 80-23 is partly new capacity (75,000 KW) using coal and biomass, partly existing capacity (86,000 KW) using a mixture of fuels ("other"). Thus "total" number of facilities for FY 1980 and the "total facilities to date" is one less than the sum of filings by category.

TABLE IV

SMALL POWER PRODUCTION FACILITIES (no. filings) and capacity in KW

TYPE SPP	FY 1980			FY 1981			FY 1982 to Date			TOTAL to date
	New	Existing	Total	New	Existing	Total	New	Existing	Total	
Hydro	(5) 82,146	(6) 34,862	(9) 1/ 87,008	(5) 25,613	(3) 8,958	(8) 34,571	(8) 12,900	(3) 3,400	(11) 16,300	(28) 137,907
Wind	(3) 76,008	(0) —	(3) 76,008	(21) 23,799	(0) —	(21) 23,799	(30) 99,799	(0) —	(30) 99,799	(54) 199,606
Biomass	(1) 80	(0) —	(1) 80	(16) 236,304	(1) 20,000	(16) 256,304	(11) 136,380	(2) 12,500	(13) 148,880	(30) 405,324
Waste	(2) 675	(0) —	(2) 675	(2) 13,375	(0) —	(2) 13,375	(1) 450	(0) —	(1) 450	(5) 14,500
Geothermal	(1) 76,000	(0) —	(1) 76,000	(1) 80,000	(0) —	(1) 80,000	(2) 62,500	(1) 11,000	(3) 73,500	(5) 229,500
Solar	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —	(2) 150	(0) —	(2) 150	(2) 150
Other	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —	(0) —
Total SPPF	(12) 234,879	(6) 34,862	(16) 1/ 239,741	(44) 379,181	(4) 28,958	(48) 408,139	(54) 312,187	(6) 26,979	(60) 339,107	(124) 2/ 986,987

1/ Because QF80-16 is partly new capacity (15,000 KW), and partly existing capacity (7,915 KW), the facility is listed under "new" filings and again under "existing" while being counted as one facility under "total". Because QF80-17 is partly new capacity (10,925 KW) and partly existing capacity (7,925 KW), it is also listed under "new" and "existing" and counted as one facility under "total". Thus "total no. of filings" is not the sum of the number of "new" plus the number of "existing" facilities.

2/ Because QF81-35 is partly biomass cogeneration capacity (1,348 KW) and partly biomass small power production capacity (5,069 KW), the facility is listed under cogeneration filings and again under small power production filings. Thus, the total number of filings represented in Tables II and III is not the sum of cogeneration facility filings plus small power production facility filings.

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: New England

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80- 1	Lawrence Hydro	Lawrence,MA	C	SP-H	--	5/30/80	15,000	--		
80-16	Boott Mills	Lowell,MA	C	SP-H	--		15,000	7,915		Tolled at Co. request
80-17	Vermont Marble	Proctor,VT	C	SP-H	--	1/28/81	10,925	7,925		
81- 1	Madison Paper	Somerset Cty,ME	N	SP-H	--	--	--	3,650		
81-11	US Windpower	Crotched Mt,NH	N	SP-W	--	--	600	--		
81-13	EG&G	Fall River,MA	C	C-CT	CO	7/23/81	580,000	--	1/87	
81-14	U Mass Med.	Worcester,MA	C	C-S	NG	6/04/81	--	5,000	3/76	
81-17	Norton	Worcester,MA	C	C-S	NG	7/27/81	--	6,000		
81-23	N.E.A.F.	Winchester,NH	C	SP-B	--	9/16/81	2,500	--		
81-28	Clark U.	Worcester,MA	C	C-DF	*	7/27/81	1,800	--	5/81	*NG & FO2
81-47	Blackstone	Central Falls,RI	N	SP-H	--	--	678	--		
81-65	Pequod	Lincoln, NH	C	SP-B	--	12/10/81	7,500	--		
81-67	G.E. Credit	Westbrook,ME	N	C-S	BIO	--	46,700	--		
81-68	Brattleboro S.F.	Brattleboro,VT	C	SP-B	--	12/4/81	325	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: New England

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
81-67-001	G.E. Credit & Scott Paper	Westbrook, ME	C*	C-S	BIO	1/26/82	46,700*	--		*Resubmittal of QF81-67-000 as application
82-14	New Hampshire Hydro	Merrimack Cty, NH	N	SP-H	--	--	2,800	--		
82-21	Wm. Pinchbeck	Guilford, CT	N	SP-B*	--	--	150	--		*Also cogenerates
82-52	Dan K. Darrow	Newfane, VT	C	SP-H	--		5	--		
82-54	North Canal	Lawrence, MA	C	SP-H	--		--	2,520		
82-58	Pittsfield	Barnstead, NH	N	C-S	BIO	--	1,800	--		
82-74	Mass Hydro Assoc.	Lowell, MA	C	SP-H	--		--	500		
82-79	Steamco, Inc.	Lakeville, MA	C	C-*	CO		1,600	--	4/82	*Fluidized Bed Comb. to Steam

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: Mid Atlantic

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	CAPACITY (KW) EXISTING	START INSTAL	NOTES
80- 3	Buffalo Color	Buffalo,NY	C	C-S	F06	6/26/80	--	5,000	1949	
80-14	Hydro Dev.Grp.	Gouverneur,NY	N	SP-H	--	--	--	1,600		
		Gouverneur,NY					--	900		
		Pyrites,NY					--	1,250		
		Dexter,NY					--	1,740		
80-20	Hoffmann-LaRoche	Belvidere,NJ	C	C-D	F06	10/26/81	23,300	--	3/82*	*Start up date
81-15	Chittenden Falls	Stockport,NY	N	SP-H	--	--	2,500	--		
81-18	Trenton Dist.	Trenton,NJ	C	C-SI	NG	6/1/81	12,000	--	6/81	
81-30	ARCO Polymers	Monaca,PA	C	C-S	CO	8/10/81	31,500	--	3/80	
81-54	Intnat'l Paper	Saratoga Cty,NY	N	SP-H	--	--	--	5,300		
81-56	Burlington Env'l	Vincentown,NJ	C	SP-B	--	11/6/81	10,000	--		
81-61	Kramer Landfill	Mantua,NJ	C	SP-B	--	12/4/81	10,000	--		
81-63	Harris Landfill	Mullica Hill,NJ	C	SP-B	--	12/4/81	10,000	--		

Appendix B
~~Page 11 of 31~~

FACILITY FILINGS BY REGION
FY 1982

REGION: Mid Atlantic

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-10	American Gas Rec. Delta Altoona LF	Blair Cty, PA	C	SP-B	--	1/8/82	10,000	--		
82-53	Hammermill Papers	Erie, PA	N	C-S	BIO CO O*	--	--	17,175 14,489 3,675		*Incidental NG,FO
82-75	Wheelabrator Frye	Peekskill, NY	C	SP-B	--		55,000	--		
82-83	Hooker Chemicals	Niagara Falls,NY	C	C-S	BIO		--	42,400	4/78	
82-93	Wehran Energy	Dover Twnshp,NJ	C	SP-B	--		420	--		

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: South Atlantic

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	CAPACITY (KW) EXISTING	START INSTAL	NOTES
80- 9	Brooks Cty Dairy	Quitman,GA	C	SP-B	--	9/11/80	50	--		
80-12	Singer Furniture	Roanoke,VA	C	C-S	BIO	9/11/80	400	--	9/80	
80-18	Philip Morris	Chester,VA	N	C-S	CO	--	10,000	--	12/82	
80-19	Cranston Print	Fletcher,NC	C	C-S	CO*	10/28/80	3,000	--	5/79	*Alt. oil/gas
80-23	Union Camp	Savannah,GA	C	C-S	* CO*	12/15/80	75,000	86,000	1930 1980	*BIO,NG,WASTE *CO,BIO
80-24	Monsanto	Escambia Cty,FL	N	C-S	NG	--	--	16,000	1957	*NG,FO6
80-30	J&F Rosenthal	Louisa,VA	N	SP-W	--	--	4	--		
81- 5	J. Eckland	Great Falls,VA	C	SP-W	--	2/12/81	4	--	11/80*	*Completion date
81-16	Milliken & Co.	Spartanburg,SC	N	SP-H	--	--	--	8		
81-19	Resources Recov.	Dade Cty,FL	N*	SP-B	--	--	76,000	--		*Petition challenging qualifying status has been filed
81-22	US Sugar	Bryant,FL	N	SP-B*	--	--	--	20,000		*Bagasse
81-57	City of Tampa	Tampa,FL	C	SP-B	--	10/29/81	45,000	--		
81-59	USS Agri Chem	Fort Meade,FL	C	C-S	WA	11/25/81	32,000	--		
81-62	Nichols Prod.	Nichols,FL	N	C-S	WA	--	13,280	--	8/81	
81-69	Occidental Chem.	Hamilton Cty,FL	C	C-S	WA*	12/24/81	15,000	--		*Waste heat from chem. process reaction

FACILITY FILINGS BY REGION
FY 1982

REGION: South Atlantic

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	CAPACITY (KW) EXISTING	START INSTAL	NOTES
82-16	Intnatl. Minerals & Chemical Corp.	Mulberry, FL	N	C-S	WA	--	8,000	--		Waste heat from chemical process
82-44	E.L. Copley III	Tilghman's Neck, MD	C	SP-SO	--	3/12/82	50	--		
82-47	Rockfish Corp.	Rockfish, VA	C	SP-H	--		--	400		
82-68	Hercules Inc.	Covington, VA	C	C-S	NG		600	--	10/81	
82-71	J.R. Ellen	Chatam Cty, NC	N	SP-H	--	--	180	--		
82-97	Wheelabrator-Frye	Baltimore, MD	C	SP-B	--		47,000	--		

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: East North Central

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80- 4	Con. Water Pwr.	Wis. Rapids,WI	C	SP-H	--	*	--	(20,820)*		*Application denied
80-21	French Paper	Niles,MI	C	SP-H	--	10/28/80	--	1,400		
80-25	Granite City	Granite City,IL	C	C-*	CO	**	--	(10,000)**		*Chem. energy-bottoming **Application denied
80-27	Quaker Oats	Pekin,IL	C	C-S	NG	12/18/80	--	1,500	1949	
80-28	Stieren Farms	Galesburg,IL	C	SP-WA*		12/21/81	500	--		*Applicant identifies methane gas from an abandoned coal mine as waste
80-31	City of Evanston	Evanston,IL	N	SP-W	--	--	4	--		
81-10	S.D. Warren	Muskegon,MI	N	C-S	CO	--	--	23,000		
81-37	Vistron Corp.	Cleveland,OH	N	SP-WA*	--	--	13,000	--		*Waste heat
81-46	Energy Conver.	Cincinnati,OH	N	SP-B	--	--	50,000	--		

Appendix B
~~Page 15 of 31~~

FACILITY FILINGS BY REGION
FY 1982

REGION: East North Central

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-25	Stone Container Corp.	Coshocton, OH	C	C-S*	BIO	2/11/82	16,500	--	5/81	*Stirling
82-82	Urban-Refergy Skokie Ptnrshp	Skokie, IL	C	SP-B	--		5,500	--		

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: East South Central

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80-11	Hunt Wesson	Memphis,TN	C	C-S	NG	9/17/80	1,000	--	2/80	
81- 4	Dickerson Lumber	Glasgow,KY	C	SP-B*	--	1/28/81	1,000	--		*Cogeneration ability
81-20	Anderson Forest	Tompkinsvil,KY	C*	SP-B	--		2,800	--		*Incomplete application
81-27	Koppers	Tie Plant,MS	C	C-S	BIO	8/26/81	750	--	1978	
81-32	Alabama Pulp	Perdu Hill,AL	C	C-S	BIO	8/26/81	--	48,000	5/77	
81-70	Memphis Hardwood	Memphis,TN	C	C-S	BIO	12/24/81	--	1,268	9/81	
81-71	Memphis Hardwood	Grenada,MS	C	C-S	BIO	12/24/81	527	--	6/81	

FACILITY FILINGS BY REGION
FY 1982

REGION: East South Central

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-4	Huntsville Micro.	Huntsville, AL	C	SP-B	--	12/24/81	80	--		
82-7	Travenol Lab.	Cleveland, MS	C	C-S	NG	12/24/81	400	--	1982	
82-32	J. Clyde Roberson	Putnam Cty, TN	C	SP-WA*	--		450	--		*Applicant identifies unmarketable NG as waste
82-90	Donald R. Nunley	Laager, TN	N	SP-W	--	--	15	--		

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: West North Central

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	EXISTING	START INSTAL	NOTES
80- 2	Ottumwa Water	Ottumwa,IA	C	SP-H	--	6/18/80	--	3,000	1931	
80- 5	Reserve Mining	Silver Bay,MN	N	C-S	NG	--	--	127,750	1954	
80-29	Larry L. Lund	*	*	*	--	*	*	*		*Notice resubmitted under docket QF 81-24
80-32	Ford-Twin Cities	St.Paul,MN	N	SP-H	--	--	--	9,132		
81-24	Larry Lund	Fairfax,MN	N	SP-W	--	--	10	--		
81-31	J.A. Miller	Kearney,NE	C	SP-W	--	8/26/81	10	--		
81-34	Hach	Elkader,IA	C	SP-W	--	8/31/81	10	--		
81-41	Poock	Sumner,IA	C	SP-W	--	9/25/81	10	--		
81-42	Root	Holy Cross,IA	C	SP-W	--	10/19/81	10	--		
81-43	Tempus	Aurora,IA	C	SP-W	--	9/25/81	10	--		
81-44	Comstock	Lake City,IA	C	SP-W	--	8/81/81	10	--		
81-48	Grundmeier	Storm Lake,IA	C	SP-W	--	10/9/81	10	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: West North Central

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-2	John Deere Comp.	Waterloo, IA	C	C-S	CO	12/31/81	--	14,500		
82-22	Richard Walker	Cambridge,IA	C	SP-W	--	2/11/82	10	--		
82-23	Vulcan Materials	Wichita,KS	C	C-CT	NG	3/16/82	33,730	--	1/82	
82-26	Bi-State Dev.	St. Louis, MO	N	C-S	BIO	--	80,000	--	1986*	*Startup
82-38-000	Robert Hetzler	Morton Cty, ND	N	SP-W	--	--	20	--		
82-38-001	Robert Hetzler*	"	C	"	--	--	"	--		*Resubmittal of QF82-38-000 as application

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: West South Central

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	CAPACITY (KW) EXISTING	START INSTAL	NOTES
80- 6	Power Systems & Great Lakes Carb.	Port Arthur, TX	C	C-*	WA**	8/8/80	75,000	--	1981	*Bottoming-3 waste heat recovery boilers+1 CT **Volatiles in petro coke feed stock
80-15	Glen L. Custer	Copan, OK	C	SP-WA*	--		175	--		*Applicant identifies 'waste NG from a stripper oil well' as waste
81-25	Tulsa Energy	Hughes Cty, OK	C	SP-WA*	--		375	--		*Applicant identifies 'NG sources: a byproduct of oil production; of insufficient quantity to sell commercially; too far from a gas gathering pipeline; or flared or burned NG' as waste
81-26	H.L. Ayers	Crowell, TX	N	SP-W	--	--	30	--		
81-29	H.M. Browning	Port Lavaca, TX	C	SP-W	--	8/26/81	4	--		
81-38	McEachern Farms	Hale Cty, TX	C	SP-W	--	9/16/81	25	--		
81-45	Votaw	Eufaula, OK	N	SP-W	--	--	1	--		
81-49	Energy Adv.	Brookshire, TX	N	SP-W	--	--	10	--		
81-60	Callison	Waynoka, OK	N	SP-W	--	--	25	--		
81-66	Nutter	Waynoka, OK	N	SP-W	--	--	25	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: West South Central

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-3	Petro-Tex Chem.	Houston, TX	N	C-S	NG	--		70,000*	1942	*Produces 34 MW and keeps one generator on standby
82-19	Dow Chemical	Brazoria Cty, TX	N	C-CT	NG	--		600,000		
82-28	Ora Mae Mell	Stockton, TX	N	SP-W	--	--	5	--		
82-29	Sam Sisk	Levelland, TX	N	SP-W	--	--	5	--		
82-31	Randy Holman	Choctaw, OK	N	SP-W	--	--	3	--		
82-35	L.A. Davenport	Sarulpa, OK	N	SP-W	--	--	2	--		
82-36	C.E. American Pole	Houston, TX	N	SP-W	--	--	4	--		
82-41	Kenneth Scott	Tahoka, TX	N	SP-W	--	--	5	--		
82-42	E. Peter Garber	Galveston, TX	N	SP-W	--	--	5	--		
82-43	Oklahoma Dept. of Transportation	Beckham Cty, OK	N	SP-W	--	--	25	--		
82-46	Union Carbide	Hahnville, LA	N	C-S*	NG	--	--	**	1976	*Bottoming **Mechanical power output
82-49	W.G. Schmeltz	Oklahoma City, OK	N	SP-W	--	--	2	--		
82-51	E&B Smith	Eufaula, OK	N	SP-W	--	--	10	--		
82-56	Union Carbide	Hahnville, LA	N	C-CT	NG	--	--	9,600		
82-57	Keith Moore	Youkon, OK	N	SP-W	--	--	5	--		
82-60	T.E. McClellan	Piedmont,, OK	N	SP-W	--	--	4	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: West South Central cont.

DATE: 4/1/82

QF#	NAME	CITY, STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-61	Mr.& Mrs. Davis	Oklahoma City, OK	N	SP-W	--	--	1	--		
82-69	Diamond Shamrock	LaPorte, TX	N	C-CT	NG	--	200,000	--	6/80	
82-72	Gene O. Staten	Oklahoma City, OK	N	SP-W	--	--	1	--		
82-73	Union Carbide	Texas City, TX	C	C-CT	NG		--	75,000		
82-76	Walter R. Stretch	Muskogee, OK	N	SP-W	--	--	2	--		
82-77	Oklahoma Center for Science &Arts	Oklahoma City, OK	N	SP-SO	--	--	100	--		
82-81	W.D. Bliss	Houston, TX	C	SP-B	--		30	--		
82-84	E.B. Meador Jr.	Oklahoma City, OK	N	SP-W	--	--	1	--		
82-87	Fred Chapman Jr.	Ardmore, OK	N	SP-W	--	--	5	--		
82-88	Leland L. Goodson	Enid, OK	N	SP-W	--	--	1	--		
82-91	Robert C. Huey	Piedmont, OK	N	SP-W	--	--	2	--		
82-96	Able Energy Sys.	Oklahoma City, OK	N	SP-W	--	--	10	--		
82-101	George A. Platt	Bayton, TX	N	SP-W	--	--	10	--		

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: Mountain

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80- 8	Twin Falls Canal	Twin Falls,ID	C	SP-H	--	9/2/80	8,921	--		
80-26	Argonne	Idaho Falls,ID	C	C*	NUC	12/12/80	--	19,500	1974	*Nuclear Facility. Waste heat used to cog. steam
81-39	Eldridge & Son	Ely,NV	C	SP-H	--	8/16/81	35	--		
81-72	May-Mac	Lambe,NM	N	SP-W	--	--	10	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: Mountain

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-30	Pacific Star,Inc.	Afton, WY	N	C-S	BIO	--	5,000	--		
82-39	Albert F. Millet	Santa Fe, NM	C	SP-W	--		10	--		
82-48	Nornev Demon. Geothermal Co.	Beowawe Geo. Field, NV	C	SP-G	--		13,500	--		
82-102 -000	Energenics Sys.	Lyons, CO	N	SP-H	--	--	1,650	--	1982	
82-102 -001	Energenics Sys.*	"	C	"	--		"	--	"	*Resubmittal of QF82-102 -000 as application
82-103 -000	Energenics Sys.	Leadville, CO	N	SP-H	--	--	2,803	--		
82-103 -001	Energenics Sys.*	"	C	"	--		"	--		*Resubmittal of QF82-103 -000 as application

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: Pacific

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW) NEW	CAPACITY (KW) EXISTING	START INSTAL	NOTES
80- 7	S.San Joaquin	Manteca,CA	C	SP-H	--	9/17/80	2,300	--		
80-22	Republic Geo.	Imp.Valley,CA	C	SP-G	--	4/27/81	76,000	--		
81- 2	Merced Irr.	Merced Cty,CA	C	SP-H	--	1/2/81	2,800	--		
81- 3	Diamond Walnut	Stockton,CA	N	SP-B*	--	--	4,500	--		*Also noticed qualification as cog. facility
81- 6	Canners Steam Co.	Terminal Is,CA	C	C-CT	NG	2/26/81	2,600	--		
81- 7	Occidental Geo.	Lake Cty,CA	C	SP-G	--	12/11/81	80,000	--		
81- 8	Sea World	San Diego,CA	C	C-S	NG	9/4/81	1,260	--		
81-12	American McGaw	Irvine,CA	C	C-S	NG	3/25/81	2,800	--	5/81	
81-21	Simpson Paper	Anderson,CA	N	C-S	NG	--	32,200	--		
81-33	Warm Springs Res.	Warm Spr.,OR	N	SP-H	--	--	19,600			
81-35	Hudson Lumber	Anderson,CA	C	C-S SP-B	BIO	9/25/81 *	1,348 5,069	--	10/82	
81-36	Watson Biogas	Carson,CA	C	SP-B	--	11/6/81	1,700	--		
81-40	Merck & Co.	San Diego,CA	N	C-S	NG	--	20,859	--	12/82*	*Completion Date
81-50	Fayette Mnf.	Alameda Cty,CA	C	SP-W	--	10/20/81	22,500	--		
81-52	Arcata Lumber	Smith River,CA	C	SP-B	--	10/20/81	10,000	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: Pacific

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80-70-001	S.San Joaquin -Frankenheimer	Oakdale, CA	C	SP-H	--	1/24/81*	4,700	--		*By operation of law
81-8-001	Sea World*	San Diego, CA	C	C-CT	NG	2/11/82	690**	--		*Addition to QF81-8-000 **Additional capacity
82-1	Glenn Mitchell	Pine Valley, CA	N	C-D	FO2	--	25	--		
82-5	Republic Geother.	Imperial Val.,CA	C	SP-G	--	12/24/81	49,000	--		
82-6	Mercy Hospital	San Diego, CA	C	C-S	NG	2/12/82*	(800)	--		*Denied
82-8	Buckeye Intnat'l Finance Corp.	Boulevard, CA	N	SP-W	--	--	1,000*	--		*25 units, 40KW each
82-9	Boeing	Auburn, WA	N	C-CT	NG	--	9,000	--		
82-11	Union Tribune	San Diego, CA	N	C-CT	NG	--	2,800	--		
82-12	Getty Synthetic Fuels	Orange Cty, CA	C	SP-B	--	1/8/82	5,700	--		
82-13	Wind Energy One	Boulevard, CA	N	SP-W	--	--	280	--		*7 units, 40KW each
82-15	Gorge Energy	Bingen, WA	C	SP-B	--	1/8/82	5,000	--		
82-17	Valley Tennis	San Diego, CA	N	C-SI	NG	--	13	--	1/81	
82-18	Magma	Imperial Val,CA	N	SP-G	--	--	--	11,000		
82-20	Imotek, Inc.	Sacramento, CA	C	C-S	BIO	2/16/82	8,500	--	12/80	

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: Pacific cont.

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
81-55	Magie	Boulevard, CA	N	SP-W	--	--	40	--		
81-58	Shroder	Boulevard, CA	N	SP-W	--	--	445	--		
81-64	Caterpillar	San Leandro, CA	C	C-GT	NG	12/31/81	2,070	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: Pacific cont.

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-24	Pacific Telephone	San Diego, CA	C	C-SI	NG	2/16/82	5,500	--	2/81	
82-27	Rodeffer	Sun City, CA	C	C-S	BIO		375	--		
82-33	Windpower Partner	Livermore, CA	N	SP-W	--	--	5,000*	--		*100 units, 20 KW each
82-34	ITT Continental Baking Co.	San Pedro, CA	C	C-CT	NG	3/12/82	894	--	6/82	
82-37	Turbowind, Inc.	San Diego, CA	N	SP-W	--	--	856	--		
82-45	V.Lund/Villa Apt.	Escondido, CA	N	C-CT	NG	--	75	--	1/81	
82-50	Edward Hines Lumber Co.	Hines, OR	N	SP-B	--	--	--	8,000		
82-55	Mercy Hospital	San Diego, CA	N	C-DF	NG	--	--	400		
82-59	Community Linen	Stockton, CA	C	C-CT	NG		500	--	8/82	
82-62	Westfir Energy	Westfir, OR	C	SP-B	--		--	4,500		
82-63	Westfir Energy	Westfir, OR	C	SP-B	--		7,500	--	2/83	
82-64	Chevron,USA	Bakersfield, CA	C	C-S	FO		4,275	--	2/82	
82-65	Chevron,USA	Taft, CA	C	C-CT	NG		10,000	--	2/82	
82-66	Chevron,USA	McKittrick, CA	C	C-CT	NG		7,500	--	4/82	
82-67	Chevron,USA	McKittrick, CA	C	C-CT	NG		2,500	--	2/82	

Appendix B
Page 28 of 31

FACILITY FILINGS BY REGION
FY 1982

REGION: Pacific cont.

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
82-80	Windfarms,Ltd.	Solono Cty, CA	C	SP-W	--		12,500	--		
	"	"	"	"	--		5,000	--		
	"	"	"	"	--		10,000	--		
	"	"	"	"	--		15,000	--		
	"	"	"	"	--		5,000	--		
	"	"	"	"	--		5,000	--		
	"	"	"	"	--		10,000	--		
	"	"	"	"	--		5,000	--		
	"	"	"	"	--		25,000	--		
82-85	Consol. Hydro	Shasta Cty, CA	N	SP-H	--	--	750	--		
82-86	Consortium of Alternate Energies	Lemon Grove, CA	C	C-CT	O*		560,000	--	1984	*Solar
82-89	El Encanto Bldg.	Coronado, CA	N	C-CT	NG	--	150	--		
82-92	Sterling Beckwith	Paradise, CA	N	SP-H	--	--	20	--		
82-94	James C. Roberts	San Marcos, CA	N	C-CT	NG	--	500	--		
82-95	GeoEnergy, Inc.	Martell, CA	C	C-CT	NG		54,500	--		
82-98	Kimberly-Clark	Fullerton, CA	C	C-CT	NG		23,200	--	1983	
82-99	Great American	National City,CA	C	C-SI	NG		1,950	--	1/81	
82-100	CA Portland Cement	Colton, CA	C	C-S*	CO		25,000	--		*2 units bottoming-cycle 1 unit steam turbine

FACILITY FILINGS BY REGION
FY 1980, FY 1981

REGION: Non-contiguous US

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
80-13	Windfarms,Ltd.	Oahu,HI	C	SP-W	--	10/3/80	76,000	--		

FACILITY FILINGS BY REGION
FY 1982

REGION: on-contiguous US

DATE: 4/1/82

QF#	NAME	CITY,STATE	FIL TYPE	TYPE FAC	COG FUEL	CERT DATE	CAPACITY (KW)		START INSTAL	NOTES
							NEW	EXISTING		
	No filings									

JAMES A. MC CLURE, IDAHO, CHAIRMAN

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DON NICKLES, OKLA.	PAUL E. TSONGAS, MASS.
JOHN P. EAST, N.C.	BILL BRADLEY, N.J.
JOHN HEINZ, PA.	

MICHAEL D. HATHAWAY, STAFF DIRECTOR
CHARLES A. TRABANDT, CHIEF COUNSEL
D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

April 23, 1982

Mr. Frederick S. Benson III
Vice President
American Paper Institute, Inc.
1619 Massachusetts Avenue N.W.
Washington, D.C. 20036

Dear Mr. Benson:

Enclosed are questions which the minority staff has requested you answer for the record.

In view of the impending markup on S. 1885, and S. 1966, would you please respond to these questions within five days so that the record can be completed quickly.

Very truly yours,

Marilyn Burkhardt
Counsel

Enclosure
MB:bn

QUESTIONS FOR HEARING RECORD ON S. 1885 AND S. 1966

American Paper Institute/Mr. Nicholson

1. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which woul give the States discretion to grant utilities exemptions on a case-by-case basis. Please provide the American Paper Institute's views on the amendment.

2. Could you provide the Subcommittee with documented cases which you believe demonstrate that 100% utility ownership of cogeneration subsidiaries will inhibit timely development of cogeneration opportunities.

Response of the
American Paper Institute
to Additional Questions of the
Subcommittee on Energy Regulation

April 28, 1982

RESPONSE TO QUESTION 1

The paper industry considers that there may be some merit in the proposal to allow the states to extend the 50% ownership limitation on a case-by-case basis, but the industry would urge the application of constraints which would ensure appropriate competitiveness.

RESPONSE TO QUESTION 2

API has already provided a supplemental statement highlighting the problems Potsdam Paper Corporation is having with Niagara Mohawk in negotiating a long-term contract for sale of its hydroelectric power. This is a good example of a utility stalling contract negotiations with a private generator due to the utility's partial ownership in a company wishing to involve itself in a private generation project. There are other cases similar to this one experienced by the forest products industry.

JAMES A. MC CLURE, IDAHO, CHAIRMAN
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D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

April 23, 1982

Mr. Michael J. Zimmer
Washington Counsel
Cogeneration Coalition, Inc.
1828 L Street N.W.
Washington, D.C. 20036

Dear Mr. Zimmer:

Enclosed are questions which the minority staff has requested you answer for the record.

In view of the impending markup on S. 1885, and S. 1966, would you please respond to these questions within five days so that the record can be completed quickly.

Very truly yours,

Marilyn Burkhardt
Counsel

Enclosure
MB:bn

QUESTIONS FOR HEARING RECORD ON S. 1885 AND S. 1966

Cogeneration Coalition, Inc./Mr. Zimmer

1. Please provide the Subcommittee with a list of the members of the Cogeneration Coalition.
2. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which would give the States discretion to grant utilities exemptions on a case-by-case basis. Please provide the Cogeneration Coalition's views on the amendment.

Cogeneration Coalition, Inc.
1828 L Street, N.W.
Washington, D.C. 20036
Phone (202) 887-5200

May 5, 1982

Ms. Marilyn Burkhardt
Counsel
Committee on Energy and Natural Resources
Subcommittee on Energy Regulation
3202 Dirksen Senate Office Building
Washington, D. C. 20510

Dear Marilyn:

Enclosed are the responses to the various questions which the minority staff has requested answers for the record in correspondence dated April 23, 1982.

1. The members of the Cogeneration Coalition, Inc. are: Kimberly Clark Corp., Brooklyn Union Gas Company, Great Lakes Carbon Company, National Urgan Energy Corp., Daverman & Associates, Energenics Systems, Inc., Entek Research, Inc., Williams & Works' Industrial Co-Energy Systems, and Enegrid Investments Ltd. Membership applications are currently pending for two other companies which include a major equipment manufacturer and natural gas distribution company. The Coalition has also established advisory relationships with other such organizations as: Alliance to Save Energy, League of Women Voters, Environmental Policy Center, State Energy Office of California, National Taxpayers Union and the American Gas Association.

2. The Cogeneration Coalition, Inc. still subscribes to the views and recommendations contained in its testimony before the Subcommittee on April 19, 1982 on S.1885. In that testimony, we indicated that consideration of S.1885 was premature at this time.
   However, if this Subcommittee and Committee are predisposed to consider S.1885, then the recommendations of Ms. Shanaman on behalf of NARUC bear close scrutiny.

The record before this Committee does not substantiate the contention that the ownership limitation has impeded electric utility investment in cogeneration facilities. However, if such detrimental effects can be shown on the record before this Committee, then the Coalition would support the suggested amendment of NARUC which would forego repealing the ownership limitation in favor of amending language to Section 210 which would give the states discretion to grant utilities exemptions on a case-by-case basis. Such an amendment should incorporate the recommended modifications in Attachment 1 to this correspondence. Furthermore, support for such an amendment is expressly conditioned upon this Committee adopting amendments to address the issues raised by the recent decision in American Electric Power Service Company v. FERC dealing with full avoided costs and interconnection standards for qualifying facilities.

The Committee may also wish to consider a separate amendment to S.1885 to prevent the prospect of cross subsidization and unfair practices caused by expanded ownership opportunities for cogeneration facilities. Some desirable specifications to address that concern are enclosed as Attachment 2 to this correspondence.

Finally, a recent article on this issue published in Energy Management is enclosed as Attachment 3.

If we can offer additional information or assistance on these matters, please do not hesitate to contact me further.

Sincerely yours,

Michael J. Zimmer

Michael J. Zimmer
Washington Counsel

MJZ:jdo

Enclosure

Attachment 1

NARUC Testimony

resulting in undue aticompetitive effects.[4/]

Adoption of this suggested amendment to Section 210 would carry with it the following advantages:

- State regulatory jurisdiction over electric utilities would remain unimpaired.
- Utility investment in unregulated cogeneration or small power facilities would be permitted to the extent such investment does not jeopardize the interests of the monopoly ratepayers.

[4/] This amendment may be made by striking out paragraphs 1 and 2 of Section 210(e), by redesignating paragraph (3) as (4), and by inserting the following language immediately after "(e) EXEMPTIONS.-": "(1) Except as provided in paragraph 2, qualifying cogeneration and qualifying small power production facilities shall be exempt from the Federal Power Act, the Public Utility Holding Company Act, and from State laws and regulations respecting the rates, or respecting the financial or organizational regulation of electric utilities.

"(2) A qualifying small power production facility, or a qualifying cogeneration facility which is owned by a person primarily engaged in the generation or sale of electric power (other than electric power produced solely from cogeneration or small power production facilities) shall be exempted under paragraph (1) from any provision of law or rule or regulation referred to in paragraph 1 if each State regulatory authority with jurisdiction over that person's generation or sale of electric power determines, after public notice and hearing, that such exemption WILL ~~is likely to~~ encourage cogeneration and small power production without resulting in UNFAIR, DECEPTIVE OR ~~undue~~ anti-competitive ACTS ~~effects~~ or adverse consequences for that person's ratepayers, OR FOR PERSONS NGAGED IN THE DEVELOPMENT F SUCH UALIFYING ACILITIES ITHIN SUCH STATE. In providing such an exemption for any facility referred to in this paragraph, the State regulatory authority may provide such limitations or conditions as it deems necessary to carry out the purposes of this paragraph.

"(3)(A)After consultation with State regulatory authorities, electric utilities, owners of cogeneration and small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral, as well as written data, views, and arguments, the Commission may promulgate such rules as it determines necessary to carry out the purposes of this subsection.".

(b) BEFORE JANUARY 1, 1984, THE COMMISSION IN CONJUNCTION WITH THE FEDERAL TRADE COMMISSION AND THE JUSTICE DEPARTMENT SHALL COMPLETE A STUDY AND SUBMIT A REPORT TO CONGRESS ON THE ACTIVITIES OF ELECTRIC UTILITIES UNDER THIS AMENDMENT, AND THE NEED FOR FURTHER AMENDMENTS AT THAT TIME.

Attachment 2

In order to qualify for such exemptions, a person primarily engaged in the generation or sale of electric power (other than electric power produced solely from cogeneration or small power production facilities) shall develop a plan containing adequate measures for preventing unfair, deceptive or anticompetitive acts or practices as well as undesirable rate consequences which relate to its activities within the scope of these exemptions. Such plan shall be filed with the Commission and the appropriate state regulatory authority before conducting business within the scope of these exemptions and shall include --

(1) provisions to ensure that the electric utility will not discriminate among customers, developers and designers of qualifying facilities, or lending institutions which might finance the construction of qualifying facilities.

(2) requirements that the electric or steam utility must file a tariff with the jurisdictional commission before it can provide transmission facilities or any services to the cogeneration subsidiary.

(3) requirements that the cogeneration subsidiary maintain its own accounting system, employ separate corporate officers, utilize its own operating, marketing, installation and maintenance personnel, and use separate computer facilities.

(4) provisions that the cogeneration subsidiary may deal with the parent utility only on an arms length basis.

(5) requirements that the parent electric or steam utility must provide the jurisdictional commission with a copy of any contract or agreement it has entered into with the cogeneration subsidiary within fifteen days.

(6) a prohibition upon the electric or steam utility from promoting the sale of energy from the cogeneration subsidiaries' facilities.

Attachment 2

(cont'd)

(7) a prohibition from providing or exchanging any proprietary information concerning customers to the cogeneration subsidiary unless the same information is available to the general public under the same terms and conditions.

(8) provisions that the parent utility is prohibited from basing any of its rate of return on the capitalization of the cogeneration subsidiary.

(9) provision for ability to search the books and conduct staff audits by the jurisdictional commission of the records of the cogeneration subsidiary.

An update on legislation affecting electric utility ownership of qualifying cogeneration and small power production facilities.

Attachment 3

Should Utilities Own Cogeneration Facilities?

by Michael J. Zimmer

Cogeneration is one of the foremost technologies available for improving the overall energy efficiency of many industrial processes, and at the same time, for producing significant amounts of byproduct electric power (or alternately, mechanical shaft-power). And given the future threat of possible electric power brownouts and curtailments, cogenerated power should be a welcome addition to utility generating capacity in the U.S.

The contribution decentralized power production may make, however, and the relationships that could develop between "small power producers" and public utilities, has consistently been an issue in our national energy strategy. At the time the Public Utility Regulatory Policies Act (PURPA) was passed, Congress expressed concern and uncertainty with respect to the proper role of public utilities in many energy conservation activities and focused strongly on decentralized power production.

Congress believed that public utility involvement in unregulated markets for the delivery of unregulated services potentially could lead to monopolization of those markets by interested public utilities. The Congressional response, embodied in PURPA, attempted to create a more balanced market for power by encouraging mutually beneficial relationships between decentralized power producers and electric utilities (see sidebar).

Three bills introduced in the current session of Congress would change these provisions. What are some of the issues surrounding utility involvement in cogeneration development? What impacts would the new legislation have on existing law? And what is the likelihood the legislation will pass in this session of Congress?

The utility position

Many electric utilities have taken the position that current statutory and regulatory provisions discourage them from effectively promoting cogeneration development. Specifically, federal policies interpreting PURPA as well as certain provisions of the Public Utility Holding Company Act discourage utility participation in such projects by limiting the equity ownership they may hold in qualifying facilities to a minority interest

Three new Congressional bills would provide electric utilities with ownership opportunities equal to those of private developers. The focus of this legislation is the provision in the Federal Power Act, as ammended by section 201 of PURPA, that qualifying cogeneration or small power production facilities must be owned "by a person not primarily engaged in the generation and sale of electric power.". The Federal Energy Regulatory Commission has interpreted this requirement to mean electric utilities may not own more than 50 percent of a qualifying facility.

Under these provisions, electric utilities which cogenerate continue to have their wholesale rates regulated by FERC and their retail rates regulated by state regulatory commissions. In addition, utility-owned cogenerators are subject to the prohibitions of the Public Utility Holding Company Act.

New legislation

H.R. 2876, introduced by Rep. William Alexander (D-Ark.), would eliminate the electric utility ownership limitation under PURPA from the definition of qualifying facilities. Thus, QF's owned 100 percent by an electric utility could still qualify for avoided cost payments for power sales and could be exempted from federal and state utility regulation.

H. R. 2992, introduced by Representative Cecil Heftel (D-Ha.), would give FERC the descretion to exempt qualifying cogeneration or small power production facilities from electric utility ownership limitation under PURPA if FERC finds "that such exemption is likely to encourage cogeneration and small power production without resulting in undue anti-competitive effects."

S. 1885, introduced by Senators Bennet Johnston (D-La.) and Gordon Humphrey (R-N.H.), is identical to Representative Cecil Heftel's bill.

One of the major effects of H.R. 2876 would be to ammend PURPA by expanding the exemption from the

Michael J. Zimmer is a partner of the Washington D.C.-based law firm Wickwire, Gavin and Gibbs, P.C. He specializes in the practice of energy and public utility law, serves as Washington counsel to Cogeneration Coalition, Inc., and is currently representing several individual project developers, industrial energy users and major universities on ongoing cogeneration projects.

they were unwilling at this time to make the necessary capital investments required to install such systems. The chief reasons advanced for this position were limited capital resources, lack of technical expertise, and environmental considerations.

Both EEI and AP&L consider electric utility involvement to be central to the evolution of a systems approach to cogeneration development that will successfully integrate centralized and decentralized generating technologies and optimize electricity production. EEI also stresses the utilities' need to compete on an equal footing with other potential cogenerators, arguing that industrial cogenerators have a guaranteed market for electricity under PURPA which reduces investor risk in such projects while creating false or artificial economies for industrial projects.

The chief attraction electric utilities have for more extensive involvement in cogeneration is the potential it offers for increased diversification and unregulated profits. In light of accelerating cancellations of nuclear powerplants, up to now the centerpiece of new projected generating capacity for the 1980's, dispersed power alternatives are becoming more attractive because of their relatively short lead times and more favorable capital requirements for construction. Finally, the prospects for retiring baseload powerplants and retrofitting them to install cogenerating capability offers increased revenue possibilities which the financially starved electric utility industry is starting to explore.

Other voices

The primary argument against expanding PURPA to include 100-percent utility-owned qualifying facilities is that it may lead to the type of imbalance in the electric utility position in the marketplace that PURPA was originally designed to correct. Opponents from industry and the project development community cite the lack of arms-length negotiations that could result between subsidiary and parent company, and the potential for "cream-skimming", with ratepayers left paying for unprofitable operations. Also, some recent operational and rate irregularities between utility-owned coal mines and their regulated parents have provided justifiable cause for concern.

Opponents also argue that raising possible utility ownership to 100 percent may not make that significant a difference to many utilities, since up to now few projects have received utility backing for the partial interest in qualifying facilities now allowed. Finally, many opponents believe it is premature to amend a law not yet fully implemented; that until pending litigation and uncertainty over PURPA are resolved, assertions that it has not worked should be withheld.

The American Paper Institute (API), for instance, would not disturb the present 50 percent utility-ownership ceiling. API believes 100 percent utility ownership would put the paper industry — historically a major cogenerator — in direct competition with more affluent electric utilities. API points out the unregulated paper and pulp industry does not enjoy the protected rates of return guaranteed to utilities. Because any venture into cogeneration on the part of industry is completely at the risk of the particular company, API perceives the risk will increase considerably if utilities are allowed to compete with them in unregulated power production. Other groups, including The Cogeneration Coalition, Inc., also would not disturb the 50 percent utility ownership test at this time.

The issue of utility ownership of cogeneration and small power production facilities raises a long list of questions that are of an economic, market, and anti-trust nature. While it is not possible to cover all such points here, some of the major questions are worth asking:

- Would diversification of the electric utility industry into such ventures be beneficial to ratepayers?
- Does such diversification pose new business opportunities only for large companies entering new unregulated markets, leading them to crowd out smaller project developers?
- Would more extensive utility involvement impede the innovation exhibited by the non-regulated sector, or will it enhance these efforts?
- Does such an approach foster undesirable competition within various market sectors for fuels such as gas, oil, and electricity?
- How likely is cross-subsidization, in which regulated companies might divert profits to subsidize the prices offered in competitive markets by non-regulated subsidiaries?
- Can problems of equal access be created for small power producers because of an electric utility's position in the marketplace?
- Can independent operating subsidiaries or affiliates be created? If they can, how might they affect regulated utility operations?

A hidden agenda

Congressional hearings on the utility role in cogeneration and small power production development were held on April 27 and June 3, 1981. To date, there has been no further attempt to Congress to address the issue. Staff for the Subcommittee on Energy Conservation and Power of the House Committee on Energy and Commerce advises it is unlikely there will be further consideration of this issue in this session. The Senate Subcommittee on Energy Regulation of the Senate Energy and Natural Resources Committee believes likewise.

But whether Congress addresses the matter or not, private sector developers and industrial users do have to seriously confront the message sent by the electric utility industry on this issue. It is a fact that over 3,000 MW of new power generation has been attributed to PURPA since its inception. This development has occurred in an environment fraught with tremendous uncertainty, some rancor and animosity, and in some instances, less than full electric utility cooperation. In other cases, it has occurred in conjunction with responsible utility ratemaking approaches, fair negotiations, and joint venture efforts.

The message seems to be that there is in fact a hidden agenda facing legislators, the utility industry, and private sector developers on this issue. This is especially true in light of the formidable array of constraints utilities will face in the upcoming decade and the estimated 13,000 MW of additional capacity cogeneration offers.

If good faith resolution of the central issues posed by utility ownership can be accomplished, we will move ahead in a spirit of compromise and cooperation and assure the nation's development of needed power sources. Failure to successfully resolve these issues could plunge the development of dispersed power sources back to the dark ages of the 60's and 70's. ■

Public Utility Holding Company Act to include "any investment or acquisition of any other interest" in a qualifying facility. Thus, *participating owners of qualifying facilities*, particularly electric utilities whose investment or acquisition might otherwise be subject to PUHCA, would be included in the PURPA exemption.

The Securities and Exchange Commission, which administers PUCHA, has already gone on record as opposing the part of H.R. 2876 which would effect this change, arguing in hearings before the House Subcommittee on Energy Conservation and Power that expanding the exemption "could needlessly fragment administration of the Holding Company Act," with possible adverse effects on utility investors and consumers.

The AP&L case

The primary proponent of H.R. 2876 on behalf of the electric utility industry is Arkansas Power and Light Company (AP&L). AP&L's interest stems from a pending project to gasify asphalt waste from a TOSCO refinery and subsequently pipe synthetic medium-Btu gas to industrial cogeneration facilities. AP&L's primary disagreement with PURPA centers upon an argument that utilities are discriminated against because PURPA provides the price benefits of avoided-cost payments only to non-utilities. AP&L argues it should receive the same price for cogenerated electricity as would a private facility.

In support of this recommendation, the Edison Electric Institute (EEI), the trade association representing the investor-owned segment of the electric utility industry, conducted a study of 33 high-volume, high steam-load industrial boiler owners. While the large steam users recognized the fuel-use efficiency benefits cogeneration could give them, EEI found

PURPA, PUHCA, and Cogeneration

PURPA, the Public Utility Regulatory Policies Act, was enacted as one of five statutes under the National Energy Act on November 9, 1978. The object of PURPA was to remove legislative and regulatory barriers to cogeneration and small power production, thus encouraging more efficient use of domestic energy resources. Among many requirements, PURPA:

- exempted qualifying facilities (QF's) from federal and state utility regulation;
- required electric utilities to purchase the electric power generated by these facilities, and to continue to supply them with power;
- permitted QF's access to the electric utility network by requiring utilities to interconnect with them and by facilitating voluntary "wheeling" arrangements to transport power from one electric utility to another.

Under FERC's interpretation of these provisions, each electric utility must pay qualifying facilities for their power at an "avoided cost" rate representing the incremental costs the utility avoids by not having to otherwise provide the [illegible] power the qualifying facility is producing.

[illegible] required state public utility commissions to implement these requirements, and to develop methodologies for calculating avoided-cost rates, by March 20, 1981. To date, only thirty-four states have adopted final rules implementing these requirements. Thus although FERC attributes almost 3,800 MW of new power to PURPA benefits, there has actually been little real experience under final PURPA rules.

Under PURPA, privately-negotiated settlements between qualifying facilities and utilities are still encouraged, with various amounts of state commission oversight in certain jurisdictions. Such private arrangements are in fact responsible for much of recent cogeneration and small power production development. They will probably continue to be of major importance in light of several ongoing court challenges to FERC's PURPA rules.

The most recent setback occurred on January 22, 1982, when the U.S. Circuit Court of Appeals for the District of Columbia, in a case brought by American Electric Power System Corp., vacated the full avoided-cost requirements in the FERC rules. FERC is appealing that decision, which is likely to delay resolution of the issue until next year, and which ultimately may mean ratemaking will be reopened.

In another major case decided in February 1981, FERC *v. State of Mississippi*, the U.S. District Court found several aspects of PURPA unconstitutional, including the Section 201 provisions defining qualifying facilities, and the Section 210 provisions dealing with avoided costs. The case was argued before the Supreme Court on January 19 and an opinion is expected this May or June. Still another case, *American Cyanamid Corp. v.* FERC, focusses on issues related to mechanical cogeneration facilities' exemption from incremental pricing. That case is also pending.

PUHCA, the Public Utility Holding Company Act, was enacted in 1935 to address the abuses which developed in connection with unregulated utility holding companies in the electric and gas industry during the early part of the century. Under PUHCA, administered by the Securities and Exchange Commission, registered electric and natural gas holding companies and their subsidiaries are subject to extensive regulation in the issuance of securities and the acquisition and disposition of assets.

Sections 201 and 210 (e) (1) of PURPA exempt QF's in whole or in part from PUHCA, and also ensure a facility will not be subject to PUHCA if it should become a qualifying cogeneration or small power production facility. Under newly proposed legislation such as the Alexander bill (see text), electric utilities would also be able to take advantage of this exemption from the Public Utility Holding Company Act to the extent of their investment in qualifying facilities.

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United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

April 23, 1982

Mr. William B. Marx
President
Council of Industrial Boiler Owners
11222 Silverleaf Drive
Fairfax Station, Virginia 22039

Dear Mr. Marx:

Enclosed are questions which the minority staff has requested you answer for the record.

In view of the impending markup on S. 1885, and S. 1966, would you please respond to these questions within five days so that the record can be completed quickly.

Very truly yours,

Marilyn Burkhardt
Counsel

Enclosure
MB:bn

QUESTIONS FOR HEARING RECORD ON. S. 1885 AND S. 1966

Council of Industrial Boiler Owners/Mr. Jamison

1. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which would give the States discretion to grant utilities exemptions on a case-by-case basis. Please provide the Council of Industrial Boiler Owners' views on the amendment.

cibo
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PRESIDENT
William E. Marx

May 7, 1982

Marilyn Burkhardt, Esquire
Counsel, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20530

Dear Marilyn:

This is in response to your letter of April 23, 1982, in which you asked, on behalf of the Minority Staff, for CIBO's position on a proposal that states be authorized to extend the benefits of PURPA on a case-by-case basis to cogeneration projects predominently or wholly-owned by electric utilities. While CIBO is concerned that enactment of this proposal could prejudice ratepayers and non-utility cogenerators, it believes that it is preferable to blanket Federal legislation to extend full ownership provisions to all utilities. Despite its apprehensions about even this more limited proposal, CIBO would not oppose enactment of this proposal if it is coupled with legislative action to correct the major barriers to industrial cogeneration erected by the decision in American Electric Power Services Corporation v. FERC.

As you know, CIBO strongly opposes legislation which extends, on a blanket basis, the benefits, including exemption from state and Federal utility regulations, provided by PURPA to cogeneration facilities predominently owned by electric utilities. Such action could prompt utilities to divert scarce capital from projects aimed at enhancing the reliability and reducing the cost of regulated facilities to unregulated enterprises, jeopardizing adequate service to ratepayers. In addition, utilities will only construct unregulated cogeneration units if they expect to receive a higher rate for its output than they would receive from regulated units. Thus, by facilitating construction of such projects, the legislation is unlikely to yield a sharing of the benefits of cogeneration between the utility and ratepayers.

A blanket extension of PURPA to all utility-owned cogeneration units could also lead to discrimination against non-utility cogenerators. Utilities will have an obvious incentive to agree to full avoided costs and other favorable contract terms in negotiations with their affiliates. In contrast, non-utility cogenerations may well be unable to obtain adequate rates and long-term pricing provisions needed to justify financing for projects. This risk will be particularly acute if the American Electric

Power decision, which vacated FERC's regulations requiring payment of full avoided cost and required FERC to initiate a new rulemaking and overturned the interconnection regulations, is not overturned.

While some of the risks discussed above could well occur even under the NARUC proposal, the extent of possible abuses may be mitigated under this proposal. Individualized scrutiny of these proposals by the states might well reduce the diversion of capital resources from regulated to unregulated facilities and assure that ratepayers receive some benefit for any additional costs they bear. Accordingly, while CIBO remains concerned about major expansion of utilities involvement in unregulated cogeneration activities, they could accept such a proposal if the major barriers to extension of cogeneration -- the uncertainties erected by the AEP decision -- are promptly resolved.

CIBO believes that this decision has already created very substantial barriers to industrial cogeneration. Even though the court has temporarily stayed its mandate, the possibility that the FERC's regulations will be set aside has an obvious chilling effect on industrial plans to expend scarce capital on new cogeneration projects. If new FERC regulations become necessary, a process that may require several years to complete or more, the decision will allow utilities to refuse to pay an adequate price for cogenerated power or to interconnect with cogenerators -- the very obstacles to cogeneration PURPA was enacted to overcome. Uncertainty regarding the rate at which cogenerated power may be sold can only serve to discourage companies from investing in new cogeneration projects.

We hope that this response is of assistance to you and look forward to working with you on this complex and important issue.

Sincerely,

William B. Marx

William B. Marx
President

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United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

April 23, 1982

Mr. Walker F. Nolan
Vice President
Edison Electric Institute
111 19th Street N.W.
Washington, D.C. 20036

Dear Mr. Nolan:

Enclosed are questions which the minority staff has requested you answer for the record.

In view of the impending markup on S. 1885, and S. 1966, would you please respond to these questions within five days so that the record can be completed quickly.

Very truly yours,

Marilyn Burkhardt
Counsel

Enclosure
MB:bn

QUESTIONS FOR HEARING RECORD ON S. 1885 AND S. 1966

Edison Electric Institute/Mitchell, Greenman, and Schaeffer

1. a. Does the Edison Electric Institute agree with the conclusion presented in FERC Chairman Butler's testimony that utility ownership of more than 50% of a QF, through an affilitate or subsidiary, is not precluded by statute?

   b. Would the Edison Electric Institute support a change in FERC regulations to enable companies affiliated with electric utilities to own more than 50% of QF's?

2. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which would give the states discretion to grant utilities exemptions on a case-by-case basis. Please provide Edison Electric Institute's views on the amendment.

3. Please provide the Subcommittee a list of Edison Electric Institute member companies who are interested in pursuing cogeneration projects.

   a. Describe each project, indicating what type of fuel would be used.

   b. In each case, please indicate what actions, if any, the utility has taken to pursue each project.

   c. In each case, please indicate whether the utility has sought permission from the appropriate state regulatory authority to participate in such a project, and, if so, what the status is of the proceeding.

FREDERICK L. WEBBER, Executive Vice President

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
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Tel: (202) 828-7400

May 21, 1982

Honorable Gordon J. Humphrey
Chairman
Subcommittee on Energy Regulation
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Re: Response to Written Questions for Hearing Record on S.1885 and S.1966

Dear Mr. Chairman:

In response to the written questions from the Subcommittee received on April 26, 1982, the Edison Electric Institute (EEI) respectfully submits the following answers for the record:

Question 1

Q.(a) Does the Edison Electric Institute agree with the conclusion presented in FERC Chairman Butler's testimony that utility ownership of more than 50% of a QF, through an affiliate or subsidiary, is not precluded by statute?

(b) Would the Edison Electric Institute support a change in FERC regulations to enable companies affiliated with electric utilities to own more than 50% of QFs?

A. EEI agrees with the legal analysis and conclusion presented in Chairman Butler's testimony that affiliates and subsidiaries of an electric utility are not precluded by the statutory provisions added by Section 201 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") from full and complete ownership of qualifying cogeneration and small power production facilities (QFs). EEI would support a change in the Federal Energy Regulatory Commission (FERC or Commission) Regulations to enable companies affiliated with electric utilities to own QFs to the same degree that unaffiliated entities are permitted to own QFs.

Notwithstanding EEI's support for making this change within the existing statutory framework, EEI believes that enactment of S.1885 is necessary to avoid protracted litigation which might ensue if the FERC attempts to act under existing statutory authority. At the April 19th hearing, the Department of Energy witness stated that his legal counsel reached the opposite conclusion concerning FERC's statutory authority. Furthermore, EEI is aware that other interest groups question FERC's authority to allow affiliates of electric utilities to own more than 50 percent of QF. Rather than leaving the FERC to accomplish this change which is important to the national interest (as evidenced by studies conducted by several independent researchers) on the basis of questioned authority, thereby inviting protracted litigation, S.1885 should be enacted to clarify FERC's authority.

Question 2

Q. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S.1885 which would give the states discretion to grant utilities exemptions on a case-by-case basis. Please provide Edison Electric Institute's views on the amendment.

A. EEI submits that the amendment to Section 210(e) of PURPA advocated by Ms. Shanaman on behalf of NARUC is unsound as a matter of legislative policy and would be needlessly burdensome.

Ms. Shanaman proposed that legislation repealing the limitation on electric utility ownership of QFs be foregone in favor of an amendment to Section 210 of PURPA which would give State regulatory authorities discretion to grant electric utility projects exemption from regulation on a case-by-case basis. Under the suggested amendment, State commissions would be given authority to exempt electric utility-owned cogeneration and small power production projects from Federal laws governing sales for resale in interstate commerce and regulating public utility holding companies. EEI believes that delegating discretionary authority to State commissions to grant exemptions from Federal law is not a sound legislative policy. It would be of dubious constitutionality and would also lead to an uneven application of Federal law as different

State commissions are likely to exercise in different manners their discretion to permit (e.g., New York) or deny (e.g., California) electric utilities an opportunity to own and operate unregulated cogeneration and small power production facilities.

A case-by-case approach to exemptions would also burden State commissions and discourage electric utility participation in cogeneration and small power production facilities. The threat of utility-type regulation of joint projects would be ever-present, and the need for a State commission exemption could force premature filing for exemption before the project is well-defined or could result in delays or uncertainty in implementation. As a result, industrial participants would be adverse to electric utility involvement in joint projects where the utility has more than a 50 percent equity ownership interest. In addition, Ms. Shanaman is inconsistent in opposing S.1885 because the administrative burden which would result from remedying those few situations where electric utilities might employ unfair business practices is much less than her suggested amendment to Section 210(e) of PURPA which would require a hearing on anticompetitive effects and adverse consequences to ratepayers for every utility-owned project on a case-by-case basis.

Furthermore, the suggested amendment is not required to avoid anticompetitive effects, impairment of State regulatory jurisdiction or adverse effects on the interests of utility ratepayers. State commissions presently exercise plenary investigatory and remedial powers with respect to practices of electric utilities subject to their jurisdiction and these powers are more than adequate to avoid or remedy anticompetitive effects. At the hearing, Professor Brown of the Energy Law Institute cited California and Maine as examples where the State commission had penalized electric utilities for failure to encourage QFs adequately.

S.1885 would not cause any impairment of State regulatory jurisdiction for the reasons set forth in response to Question 5. Concerning adverse effects on utility ratepayers, Mr. Mitchell explained at the hearing that the electric utility industry (in contrast to other groups) is the only participant in the administrative and legislative process that has consistently advocated a sharing of the benefits between QFs and the utility ratepayers. In seeking equal, competitive ownership opportunities, EEI has not slackened in its zeal to ensure that the utility ratepayer obtains a benefit from QF power production, regardless of the QF ownership.

Concerning State commission restrictions on diversification, EEI submits that it is in the national interest for electric utilities to be authorized to diversify into ownership of QFs on an equal, competitive basis, that these facilities are closely related to the utility's objective of satisfying the electrical requirements of its service area, and that the FERC has already exempted electric utilities from State laws and regulations restricting electric utility diversification into ownership of QFs -- up to a 50 percent equity ownership interst. S.1885 would simply extend the present exemption for electric utility investments in QFs to full equity ownership.

In summary, the amendment suggested by Ms. Shanaman is unnecessary and is inconsistent with sound legislative policy.

Question 3

Q. Please provide the Subcommittee a list of Edison Electric Institute member companies who are interested in pursuing cogeneration projects.

(a) Describe each project, indicating what type of fuel would be used.

(b) In each case, please indicate what actions, if any, the utility has taken to pursue each project.

(c) In each case, please indicate whether the utility has sought permission from the appropriate state regulatory authority to participate in such a project, and, if so, what the status is of the proceeding.

A. In the brief period that the record is being kept open, it is not possible to compile a list of EEI member companies that are interested in pursuing cogeneration projects, let alone describe each project and the actions undertaken to pursue each project. Moreover, EEI respectfully submits that such case studies would be quite expensive, largely duplicative of the independent studies mentioned in the hearing testimony and unnecessary to establish the need for the legislation.

EEI is enclosing a copy of a survey of EEI member utility diversification activities. Some of these activities would qualify under Section 201 of PURPA, but for the ownership limitation. Also enclosed is a copy of EEI's testimony in the recent House hearings concerning least cost decisions by electric utilities. That statement also includes references to electric utility activities in cogeneration and small power production. Reports prepared as a result of several recent independent studies (previously submitted at your request) also provide clear evidence of the need for and benefit from electric utility ownership of QFs. In particular, the Resource Planning Associates studies involved in-depth interviews with many companies in the six major steam-using industries.

These reports establish the need for enactment of S.1885, and the testimony of Messrs. Mitchell, Greenman and Schaeffer demonstrate that many electric utilities are interested in pursuing the available opportunities for investment in QFs if S.1885 is enacted.

Question 4

Q. Does counsel for the Edison Electric Institute believe, as a matter of law, that state regulatory authorities have authority to offer cogeneration and small power production projects a more attractive rate than the minimum rate required by PURPA?

A. Counsel for EEI believes that, as a matter of law, State commisisons do not have authority to offer QFs a more attractive rate than the maximum rate authorized under the FERC Regulations (18 C.F.R. § 292.304), which at present is also a minimum rate for new facilities, absent a negotiated agreement. The FERC Regulations, in turn, may not establish a rate for purchases from QFs which exceeds the lower of the incremental cost to the electric utility of alternative electric energy or a rate which is just and reasonable to the electric consumers of the electric utility, in the public interest and non-discriminatory. PURPA Conference Report, S. Rep. No. 95-1292, 95th Cong., 2d Sess. 98 (1978).

Question 5

Q. If we have a Federal interest in overriding local PUC regulation with respect to cogeneration and small power production, should we consider the same thing with regard to coal and nuclear investments, each of which may not be taking place at an optimum rate?

A. Neither Section 210 of PURPA nor S.1885 reflect any attempt to "override" local PUC regulation with respect to cogeneration or small power production owned by utility affiliates; and EEI believes that the scope of S.1885 should remain limited to permitting equal, competitive ownership opportunities with respect to those technologies already favored by Congress in Section 210 of PURPA -- cogeneration and small power production from renewable resources.

Electric utilities may presently structure their activities such that generating units come within FERC jurisdiction by establishing affiliates to engage in sales for resale. For example, Middle South Energy is presently constructing a nuclear plant the output of which will be sold to some of the operating companies of the Middle South System. New England Power Company owns or participates in a mix of nuclear, coal and oil-fired generation and hydroelectric facilities, the ouput of which is sold in interstate commerce for resale to the distribution company subsidiaries of the New England Electric System and others. Thus, electric utilities already have a right to structure their ownership of cogeneration and small power production facilities such that they would come within FERC jurisdiction. Local PUC regulation with respect to these facilities would be preempted, not by S.1885, but by Federal regulation of the sales for resale under the Federal Power Act.

Section 210 of PURPA explicitly states that the FERC Regulations may authorize only sales for resale, and this clear language is confirmed by the Conference Report accompanying PURPA (S. Rep. No. 95-1292, at 97).
In removing the limitation on electric utility ownership of QFs, S.1885 would not override local PUC regulation of QFs; rather it would extend the existing PURPA § 210(e) exemption from regulation under the Federal Power Act to the sales for resale by electric utility-owned QFs. Consequently, there would be no impairment of State commission regulation of electric utilities.

Concerning similar QF treatment for coal and nuclear investments, EEI believes that if the FERC and State commissions limit the benefits of PURPA to QFs which effect a demonstrable net savings of oil or gas over the life of the facility, the economics of the market will guide investment in coal and nuclear facilities. EEI views S.1885 more as a technical amendment to Sections 201 and 210 of PURPA and not as a vehicle for modifying the basic incentives for development of the power generation technologies described therein or adding additional technologies.

Question 6

Q.(a). What will be the advantage of S.1885 to Arkansas Power and Light and other members of Edison Electric Institute if the D.C. Circuit Court of Appeals' decision in the American Electric Power Service v. FERC case is not reversed?

A.(a). In their written statement (pp. 10-11), Messrs. Mitchell, Greenman and Schaeffer explained that EEI members perceive definite benefits resulting from market value pricing of the electric product from a QF as compared to cost-of-service regulated returns on original investment cost less accumulated depreciation. EEI members also perceive a potential benefit from unregulated steam sales to an industrial customer. Investment in these facilities, however, will involve new and additional risks which require a return commensurate with that expected by non-utility investors. EEI and its member companies believe that they should have an equal, competitive opportunity to participate in the ownership of these QFs. EEI also believes that the benefits to QFs under PURPA will be sufficient, regardless of QF ownership, even if the AEP decision is not reversed, and that a sharing of the benefits of cogeneration and small power production with utility ratepayers is required.

Q.(b). Should the Committee act on legislation addressing the problems created by this case prior to final court action of appeals?

A. EEI believes that S.1885 should be enacted, without amendments, to remedy a serious deficiency in the existing statutory definition of QFs for the reasons stated in its testimony. S.1885 is in the nature of a technical amendment to obtain fuller development of the Nation's cogeneration and small power production potential. There is no need to burden this simple but important legislation with controversial amendments which would prematurely dispose of issues currently subject to appeal in the Federal courts.

Honorable Gordon J. Humphrey
May 21, 1982
Page Eight

Thank you for the opportunity to give our industry's view on this important legislation. If you have any questions concerning these matters, please contact Ed Yawn at (202) 828-7672.

Sincerely,

Frederick L. Webber

FLW/tlg

Enclosures

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JOHN P. EAST, N.C.
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D. MICHAEL HARVEY, CHIEF COUNSEL FOR THE MINORITY

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

April 23, 1982

Mr. Peter W. Brown
Director
Energy Law Institute
Franklin Pierce Law Center
2 White Street
Concord, New Hampshire 03301

Dear Mr. Brown:

Enclosed are questions which the minority staff has requested you answer for the record.

In view of the impending markup on S. 1885, and S. 1966, would you please respond to these questions within five days so that the record can be completed quickly.

Very truly yours,

Marilyn Burkhardt
Counsel

Enclosure
MB:bn

QUESTIONS FOR HEARING RECORD ON S. 1885 AND S. 1966

ENERGY LAW INSTITUTE/MR. BROWN

1. Please provide the Subcommittee with a list of the founders of, and contributors to, the Energy Law Institute.

2. Ms. Shanaman, on behalf of the National Association of Regulatory Utility Commissioners, suggested an amendment to S. 1885 which would give the States discretion to grant utilities exemptions on a case-by-case basis. Please provide the Energy Law Institute's views on the amendment.

ENERGY LAW INSTITUTE,
May 6, 1982.

Ms. MARILYN BURKHARDT, *Counsel,*
U.S. Senate
Energy and Natural Resources,
Washington, D.C.

DEAR MARILYN: The following will respond to the questions appended to your letter of April 23, 1982 to me.

The founders of the Energy Law Institute were Anthony Buxton, Esq., now practicing law in Maine, and myself. Of course, the founding of the Institute was approved by the administration of the Franklin Pierce Law Center. The Institute has no contributors and is supported by the Law Center and the Institutes's own research activities.

With respect to Ms. Shanaman's suggestion, my question would be, what is the nature of the exemption to be granted by the states? If the states wish to retain the authority to require utilities to disclose or otherwise report on their cogeneration or small power production ventures (e.g. the number of such ventures, amount of investment, etc., in a given year), I see no difficulty in giving the states the discretion to withhold an exemption from such reporting requirements. However, I do see problems with giving the states the authority to withhold an exemption from conventional rate of return regulation. If states retained the power to subject utility qualifying facilities to rate of return regulation, the purposes of S. 1885 would be utterly subverted. Moreover, as I testified at the hearings, I think state regulatory agencies have significant regulatory authority over the parent operating companies to address any problems and therefore, Ms. Shanaman's suggestion would seem redundant.

Please advise if I may be of further service.

Sincerely,

PETER W. BROWN, *Director.*

National Association of Regulatory Utility Commissioners

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Rhode Island Public Utilities Commission
100 Orange Street
Providence, Rhode Island 02903

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PAUL RODGERS
Admininstrative Director
General Counsel

GAILE ARGIRO
Treasurer

May 3, 1982

Ms. Marilyn Burkhardt
Counsel
Subcommittee on Energy Regulation
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Re: Responses to Questions Concerning
S. 1885, a Bill to Amend PURPA

Dear Ms. Burkhardt:

This will respond to the questions raised by the Minority staff with respect to the NARUC's views on S. 1885, as transmitted by your letter of April 23, 1982 to Chairman Susan M. Shanaman of the Pennsylvania Public Utility Commission.

Question (1): Mr. Chiles' testimony criticized States for establishing rates for purchase of QF power that are higher than "authorized" by FERC rules (page 5). Does NARUC agree with the implication of Mr. Chiles' statement, that is that FERC has authority to establish a maximum rate for QF's, as well as a minimum rate?

Answer: It is not clear to the NARUC whether Mr. Chiles' criticism of the States' compliance with FERC regulations implementing PURPA Section 210's provisions regarding rates for utility purchase of QF power was directed toward States' possible miscalculation of "avoided costs" in accordance with the guidelines set forth in the FERC regulations,[1] or toward some States' decisions to authorize QF rates that exceed a FERC-authorized "ceiling" on such rates.

---

[1] 18 C.F.R. §§ 292.304; the factors to be considered in arriving at "avoided costs" are set forth at 18 C.F.R. § 292.304(e).

In the first case, the NARUC is unaware of any instances where a State public utility commission has failed to evaluate adequately the FERC-identified factors to be considered in calculating an electric utility's avoided costs for the purpose of determining QF rates as specified in Section 210. The NARUC is confident that State regulatory officials are relying on the FERC guidelines to the full extent mandated in its regulations, in the exercise of their legal responsibilities under PURPA and relevant State statutes.

If Mr. Chiles' statement was, however, premised on his belief that FERC has authority to establish maximum QF rate levels within which State-authorized rates must be set, the NARUC respectfully disagrees with his interpretation of the Commission's authority in this regard. As noted in FERC Order No. 69, wherein the Commission implemented the relevant sections of Section 210,[2/] the States are free to enact laws or regulations providing for even greater encouragement of cogeneration than required under the FERC regulations. Only State laws or regulations which would provide for rates lower than authorized by the Federal standards must yield to the Federal scheme.

State authority over cogeneration rates is not dependent, of course, on this explicit FERC recognition of the limits of its authority. State commissions possess independent authority, conferred by State statute, over the rates paid by electric utilities for purchase of power. Thus, while giving full consideration to the avoided cost factors identified in the FERC regulations, a State commission may decide to consider factors in addition to those specified by the Commission, such as the utility's ability to dispatch power purchased from the QF.[3/]

Question (2)(a): Does NARUC agree with the conclusion presented in FERC Chairman Butler's testimony that utility ownership of more than 50% of a QF, through an affiliate or subsidiary, is not precluded by statute?

Answer: The NARUC agrees with Chairman Butler's legal conclusion that Section 210 does not preclude such utility affiliate investments. However, we would append this legal conclusion with the recognition that utility diversification issues are uniquely within the province of State commissions' regulatory responsibilities and that the Federal government should refrain from permitting diversification activities where the appropriate State authority has not authorized the electric utility to engage in such ventures.

For these policy reasons, we believe that FERC's decision to implement Section 210 so as to limit utility affiliates to no more than 50 percent ownership of a QF was well-considered and within its authority under the statute.

Question (2)(b): Would NARUC support a change in FERC regulations to enable companies affiliated with electric utilities to own more than 50 percent of QF's?

[2/] 45 Federal Register 12214 (February 25, 1980).

[3/] See, e.g., Re: Rule-making Proceeding for Consideration of Cogeneration and Small Power Production, Idaho Public Utilities Commission (Decision Nos. 16025 and 16048, December 2 and 11, 1980), reported at 40 PUR 4th 563 (1981).

Answer: For the above-cited reasons, the NARUC would oppose any such revision to the FERC regulations which fails to provide that States would retain authority to disallow such affiliate investment activities, notwithstanding FERC approval in this regard.

Question (3): Your testimony indicates that some States have already adopted regulatory mechanisms such as preferred rates of return on equity or expedited licensing procedures in order to encourage utility investment in energy-efficient technologies. Please provide the Subcommittee with a compilation of such mechanisms.

Answer: The following represents a partial listing of regulatory mechanisms employed by State public utility commissions to encourage utility investment in energy-efficient technologies.

(a) Incentive rates of return on equity.

Illustration: In 1980, the Rhode Island Public Utilities Commission set an electric utility's rate of return on equity at 13.75 percent, a figure representing the highest in a range recommended by the State's Office of the Attorney General. Its findings regarding the utility's rate of return was explicitly based in part on its decision to reward the company for its plans to implement comprehensive conservation and load management programs.4/

(b) Mandatory utility adoption of conservation programs.

Illustration: The Michigan Public Service Commission in a 1980 decision ordered an electric utility to file a comprehensive conservation plan --using techniques which include cogeneration--in order to bring about a reduction in load growth sufficient to eliminate the need for a new power plant's construction.5/

Similar rulings have emanated from the State regulatory authorities in Connecticut6/ and California7/.

(c) Revenue increases.

Illustration: The California Public Utilities Commission granted an electric utility a $600,000 revenue increase on the basis that the utility's

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4/ Re: Narragansett Electric Company (Docket No. 1499, November 8, 1980), reported at 40 PUR 4th 498 (1981).

5/ Re: Consumers Power Company (Case No. U-5979, August 8, 1980), reported at Util. L. Rep., State (CCH) Par. 23,168.

6/ Re: Connecticut Light and Power Company (Docket No. 800403, October 9, 1980; Supp. Decision, October 17, 1980), reported at 41 PUR 4th 1 (1981).

7/ Re: Southern California Edison Company (Decision No. 92549, December 30, 1980), reported at 39 PUR 4th 640 (1981).

expenditures for a residential cogeneration demonstration project should be recoverable, due to the project's potential for benefiting consumers and adding more power to the utility's grid.[8]

(d) Allowance of future plant costs in rate base.

Illustration: The Wyoming Public Service Commission permitted costs for a utility's future plant sites to be included in its rate base, based on a finding that hydroelectric power sites were scarce and that the integral nature of these properties to another development required such treatment.[9]

(e) Allowance of CWIP in rate base.

Illustration: The Texas Public Utility Commission allowed 42 percent of a utility's construction work in progress in its rate base in order to allow it to convert to alternative fuel use.[10]

Similarly, the Kansas State Corporation Commission refused to allow a utility's additional generating plant CWIP in its rate base because the utility's management failed to consider adequately options other than building new capacity for the satisfaction of future power needs.[11]

(f) Penalty on rate of return.

Illustration: The California commission in 1979 imposed a 20 percent reduction in an electric utility's basis points for its overall rate of return due to its seriously inadequate promotion of the development of cogeneration.[12]

(g) Analysis of potential utility cogeneration opportunities.

Illustration: The Wisconsin Public Service Commission recently secured a consultant to evaluate potential utility cogeneration sites for the western portion of the State, and it directed that the electric utilities under its jurisdiction conduct a similar analysis for the eastern part of the State.[13]

8/ Re: Southern California Edison Company (Decision No. 92166, August 19, 1980), reported at 39 PUR 4th 75 (1981).

9/ Re: Pacific Power and Light Co. (Docket No. 9454, Subs. 11 and 6, March 4, 1981), reported at 40 PUR 4th 690 (1981).

10/ Re: Texas Power & Light Co. (Docket No. 3006, April 29, 1980), reported in PUR Annual 1980 Digest at 311.

11/ Re: Kansas City Power & Light Co. (Case No. ER-80-48, June 19, 1980; Correction Order, July 1, 1980), reported at 38 PUR 4th 1 (1981).

12/ Re: Pacific Gas & Electric Co. (Decision No. 91107, December 19, 1979), reported at 34 PUR 4th 1 (1980).

13/ Information supplied by the Wisconsin commission, April 27, 1982.

Ms. Marilyn Burkhardt
May 3, 1982
Page Five

Question (4): Please provide the Subcommittee with documentation of cases which you believe support your contention that State regulatory authorities have not been responsible for the lack of involvement in cogeneration by electric utilities.

Answer: Please refer to the cases cited in the answer to Question (3).

Should the Subcommittee members or staff require any additional information concerning the matters discussed herein, please feel free to contact me.

Sincerely,

Rita A. Barmann
Director of Congressional Relations

RAB/jwn

National Association of Regulatory Utility Commissioners

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PAUL RODGERS
Administrative Director
General Counsel

GAILE ARGIRO
Treasurer

April 27, 1982

The Honorable Gordon J. Humphrey
Chairman
Subcommittee on Energy Regulation
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Re: Request for Further Information Concerning Suggested Legislation In Lieu of S. 1885

Dear Senator Humphrey:

Thank you for the opportunity you provided to the National Association of Regulatory Utility Commissioners (NARUC) to present our members' views at last week's hearing concerning S. 1885 and S. 1966, bills which would amend the Public Utility Regulatory Policies Act of 1978 (PURPA). This letter will respond to the question you posed to the NARUC's witness, Chairman Susan M. Shanaman of the Pennsylvania Public Utility Commission, in connection with our suggested approach in lieu of S. 1885. As you will recall, the NARUC urged that if the need for electric utility exemption from the 50 percent limitation on ownership of qualified cogeneration and small power facilities can be demonstrated, Section 210 of PURPA should be amended to give State regulatory authorities discretion to grant such exemptions on a case-by-case basis.

Following Ms. Shanaman's presentation at the hearing, you inquired as to the average length of time taken by State commissions to complete consideration of utility rate requests. Based on an analysis of data compiled in the NARUC's 1980 Annual Report on Utility and Carrier Regulation, the national average time for completion of this process is approximately eight and one-half months. It should be noted that this average is based on all utility rate cases, rather than only those pertaining to electric utilities.

The Honorable Gordon J. Humphrey
April 27, 1982
Page Two

It also should be noted that all States have statutorily-imposed time limitations within which their public utility commissions must complete consideration of utility rate requests. Moreover, many State commissions have authority to grant interim rate increases to a utility prior to final resolution of the rate case. As a result, the length of time which is required for a full evaluation of the merits of a utility's rate increase request rarely presents an undue regulatory burden on the utility involved.

When raised in connection with our suggested approach to the 50 percent limitation in PURPA's Section 210, your question carried with it the implication that State consideration of electric utilities' exemption requests on a case-by-case basis would prolong the rate request process to an unacceptable degree. On the contrary, such exemption requests would not necessarily be addressed in the context of a utility rate case, particularly since the request would raise issues that transcend questions of rate regulation. Should the NARUC-proposed amendment to Section 210 be enacted, an electric utility would be free (subject, of course, to the various procedural requirements of the State commission(s) involved) to petition at any time for an exemption from the 50 percent ownership limitation for its otherwise qualified cogeneration or small power facilities.

We would reiterate the basic position spelled out in Ms. Shanaman's testimony: namely, that the 50 percent limitation has yet to be shown to be a genuine hindrance to electric utility investment in cogeneration and small power facilities. Furthermore, even a demonstrated instance of the detrimental impact of this limitation on availability of PURPA Section 210 benefits would be best dealt with by the State commission whose responsibility it would be to scrutinize the parent-unregulated subsidiary relationship potentially created if the limitation is removed. Protections of the utility ratepayer is the legal obligation of the State public utility commissions. Any revision to the PURPA scheme for encouraging use of energy-efficient technologies should preserve the ability of State regulators to carry out this responsibility.

Again, we appreciate the opportunity to express our members' views on these important issues. Please make this letter part of the hearings record in connection with S. 1885. Should you or your staff require any additional information on the States' position with respect to these matters, please feel free to contact us.

Sincerely,

Rita A. Barmann

Rita A. Barmann
Director of Congressional Relations

cc: Hon. Susan M. Shanaman

APPENDIX II

Additional and Supplemental Statements Submitted for the Record

STATEMENT OF SENATOR JOHN C. DANFORTH
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES

April 19, 1982

Mr. Chairman, first I would like to express my appreciation to you for taking up S. 1966 in the context of this hearing, which originally was scheduled solely to consider S. 1885. I believe that S. 1966 will prove noncontroversial and will merit the Committee's support.

S. 1966 would do one very simple thing: it would strike Section 116 of the Public Utility Regulatory Policies Act of 1978 (PURPA). In so doing, it would save hundreds of thousands of dollars for States, nonregulated utilities, and the Federal government.

Title I of PURPA seeks to encourage conservation, energy efficiency, and equitable electric rates for consumers. To accomplish this, Section 116 requires the States, through their appropriate regulatory authorities, and also nonregulated electric utilities to determine whether certain regulatory and ratemaking standards would further those policies.

The deadline for completion of this process was November 9, 1981. Nonetheless, the law requires the States and utilities to continue to report to the Department of Energy on their progress until 1990, and DOE in turn is required to report to the President and the Congress. Understandably, DOE is unclear about what these reports should contain after 1982; it does not believe that the reports should cover actual implementation of the standards.

On September 14, 1981, the General Accounting Office issued a report to the Congress entitled "Burdensome and Unnecessary Reporting Requirements of the Public Utility Regulatory Policies Act Need To Be Changed."

GAO questioned the timeliness, accuracy, and reporting categories of the data in these DOE reports. In addition, it noted that the National Association of Regulatory Utility Commissions, through its electric utility rate design study, prepares reports containing almost identical information.

GAO concluded that, while the act was intended to "provide worthwhile information to parties involved in utility rate proceedings, in a time of budget cuts and continuing utility rate increases it is necessary to carefully examine the costs and benefits associated with the regulatory requirements. This is particularly true if information serving the same purpose is available from other sources."

In 1980, according to DOE estimates, the States and non-regulated utilities expended 6,294 staff-hours on preparation of these reports. In addition, the Federal government expended $259,160 on the data collection effort. The idea of continuing this kind of wasteful and unnecessary spending for the rest of this decade is truly offensive.

In light of these considerations, GAO called the need for continued reporting "questionable." It recommended that Section 116 be repealed following completion of DOE's 1982 report:

> This would reduce the paperwork burden on both the Federal Government and the private sector, and eliminate the cost ultimately borne by the individual taxpayer. If there is future interest in the ratemaking status of States and utilities that is not satisfied by available reports, Congress can request the preparation of such reports at future times.

GAO further reported that DOE agrees with its recommendation to repeal this section of the law.

Mr. Chairman, the Subcommittee on Federal Expenditures, Research, and Rules, which I chair, is responsible for overseeing the government's information collection process. In 1980 we made a great stride forward with the Chiles-Danforth Paperwork Reduction Act, which gave the Office of Management and Budget the authority to review and veto Federal paperwork requirements. This has resulted in the elimination in the past year of one hour of paperwork for every man, woman, and child in America.

But further legislative action is needed. On March 23, along with Senators Roth, Chiles, and Eagleton, I introduced S. 2258, the Congressional Reports Elimination Act of 1981, which would eliminate or modify more than 200 reports now required by Congress. Enactment of this legislation would make an important contribution to paperwork reduction within the bureaucracy.

We in Congress often complain about government paperwork and red tape; and so when we ourselves are responsible for an unnecessary and duplicative reporting requirement like Section 116 of PURPA, we have a particular responsibility to remove it. I urge prompt action to accomplish its repeal.

With the Committee's permission, I also would like to submit for the record a letter from Christopher DeMuth, Administrator of Information and Regulatory Affairs, supporting enactment of S. 1966.

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

February 11, 1982

Honorable John C. Danforth
Chairman
Subcommittee on Federal Expenditures,
Research, and Rules
Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510

Dear Senator Danforth:

Thank you for your recent letter seeking our views on S. 1966 and S. 1967, bills that would eliminate reports to Congress which GAO suggests are no longer needed.

We too are trying to chip away at unneeded regulatory and paperwork burden on the economy through our administration of the Paperwork Reduction Act and E.O. 12291. For statutory provisions such as the ones you have identified, it is the Congress that will have to eliminate the unjustified burden.

Passage of these two bills would help in this effort. Reporting to Congress has become a major administrative burden to many agencies, and virtually every piece of legislation being enacted contains a requirement for a new report. The cumulative effect of these reports is to reduce the ability of many agencies to perform their programmatic responsibilities effectively; at the same time, I understand that many of the reports are of little or no use to the Congress itself.

I very much appreciate your interest and support in eliminating needless Federal paperwork. I should add that my office is currently completing a study of reports that will include recommendations for eliminating many of them. I would like to share this study with you when it is finished about two weeks from now.

Sincerely,

Christopher DeMuth

Christopher DeMuth
Administrator for Information
and Regulatory Affairs

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Wholesale Electric Company
Ludlow, Massachusetts
C. M. PERKINS
Salt River Project
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JAMES H. PHILLIPS
Sebring, Florida
GEORGE D. REICH
Plattsburgh, New York
HAROLD SCHIEBOUT
Sioux Center, Iowa
SIMON C. SITTERSON
Kinston, North Carolina
J. K. SPRUCE
San Antonio, Texas
GEORGE H. USRY
Athens, Tennessee
H. S. VANDERLINDEN
Harlan, Iowa
WILLIAM C. WALBRIDGE
Sacramento Municipal Utility District
Sacramento, California
ROBERT C. YOUNG
Burlington, Vermont

April 30, 1982

Honorable Gordon Humphrey, Chairman
Subcommittee on Energy Regulation
Senate Committee on Energy and Natural
Resources
3202 Dirksen Senate Office Building
3rd Floor
Washington, D. C. 20510

Dear Mr. Chairman:

Enclosed is a statement of the American Public Power Association the national service organization representing over 1,750 local public power systems in 48 states, Puerto Rico, American Samoa, Guam and the Virgin Islands, on S. 1885, a bill to amend the Federal Power Act and the Public Utility Regulatory Policies Act, and on S. 1966, a bill to eliminate unnecessary paperwork and reporting requirements contained in the Public Utility Regulatory Policies Act of 1978. Both bills were the subject of hearings held by your Subcommittee on April 19. We respectfully request that our statement be included in the official record of this hearing.

Should you or your staff have any questions concerning our views on these measures, we would be happy to respond.

Sincerely,

Alan H. Richardson
Legislative Director and
Legislative Counsel

AHR/mb

Statement of the
American Public Power Association
On
S. 1885 and S. 1966
Submitted to the
Subcommittee on Energy Regulation
Senate Committee on Energy and Natural Resources

The American Public Power Association(APPA) is the national service organization representing over 1,750 local public power system in 48 states, Puerto Rico, American Samoa, Guam and the Virgin Islands. APPA opposes S. 1885, which would remove the 50 percent utility ownership limitation from qualifying facilities contained in the Public Utility Regulatory Policies Act (PURPA), and supports S. 1966, which would repeal section 116 of PURPA.

S. 1885

Section 210 of PURPA sets forth a program designed to encourage cogeneration and small power production by: removing certain regulatory barriers to non-utility involvement in these areas; requiring utilities to purchase power from and sell power to qualifying cogeneration and small power production facilities (qualifying facilities); and establishing a framework for sales of power by qualifying facilities, which as interpreted by the Federal Energy Regulatory Commission requires that such sales be based on the purchasing utility's full avoided cost. (The Commission's full avoided cost rule was recently held invalid by the U.S. Circuit Court of Appeals for the D. C. Circuit in American Electric Power Service Corporation, et al. v. Federal Energy Regulatory Commission. A petition for rehearing en banc was recently denied by this court.)

Section 201 of PURPA denies qualification to any facility, the owner of which is "primarily engaged in the generation of electric energy...." The Commission has liberally construed this provision in favor of utility participation, to permit qualification of facilities for treatment under section 210 so long as such facilities are not more than 50 percent utility-owned.

S. 1885 would redefine the terms "qualifying small power production facility" and "qualifying cogeneration facility" to remove the utility ownership prohibition. It is suggested that this is appropriate to permit utilities to qualify for the benefits, and escape regulatory review, under the PURPA section 210 program.

APPA does not believe this measure is necessary to encourage utility involvement in cogeneration and small power production. Testifying on a similar bill before the House Subcommittee on Energy and Power on June 3, 1981, FERC Chief Advisory Counsel John O'Sullivan stated that "the Commission staff is not convinced that the 50 percent limitation on electric utility ownership of qualifying facilities has discouraged electric utility financial participation in these facilities. Furthermore, the Commission staff is not convinced that lifting the 50 percent ownership limitation and giving all the benefits of qualification would be appropriate or would increase electric utility participation in developing cogeneration or small power production...." We concur.

The statute was passed in the first place because Congress believed that (a) utilities were dragging their collective feet in entering this field and (b) the solution was to give non-utility organizations a guaranteed market, protecting them against utility stonewalling, and freeing qualifying facilities from utility-type regulation.

It is important to note that there is no existing prohibition against an electric utility -- regardless of ownership -- building and operating a small power production or cogeneration facility. Any private power company, rural electric cooperative, or public power system can get into the business right now if it finds it economically feasible to do so. Many are already taking steps to become involved in cogeneration and small power production. For utilities, these decisions are and should be based on the economics of the project.

Some of the advantages of owning a qualified facility are simply not applicable where a utility itself is the sponsor. For example, section 210 requires utilities to purchase power from, and sell power at non-discriminatory rates to, qualifying facilities. A utility,however, does not need this Federal statutory protection to purchase from and sell to itself.

Qualifying facilities are entitled to certain tax benefits which are denied to utilities. However, even before the enactment of the Economic Recovery Tax Act and its special treatment for utility property and provisions for sale of tax credits, most utilities had little if any tax liability. With the Act, any utility with more than a negligible tax liability doesn't need additional tax credits flowing from ownership of a qualifying facility, it needs a new accountant.

Unlike non-utility owners of qualifying facilities, utilities are familiar with regulation at both the Federal and the state level. Certainly the prospect of regulation over a qualifying facility is not an adequate disincentive to constructing and operating such a facility, particularly if the facility represents an appropriate economic investment.

Finally, then, we come to the real incentive -- the opportunity for utilities to become owners of qualifying facilities, sell their power to themselves at full avoided cost (or a cost above a just and reasonable cost depending on the ultimate resolution of pending litigation and the almost inevitable regulatory revision) and pass these costs on to their consumers without the Federal or the state regulatory commissions exerting, or being able to exert, any real control. The utility, freed from the ownership limitation, would be able to control the entire transaction and would have every incentive to charge itself high rates for its own power. We believe this is not in the public interest and should not be allowed.

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Section 116 of PURPA requires the submission of reports on the extent of compliance with the PURPA rate and service practice standards. These reports are due on a yearly basis through 1989.

APPA belives these reports are unnecessary and should be eliminated. We would go beyond this, however. Any benefits attributable to the PURPA title I program have already been achieved. (We are not suggesting that there have not been any benefits. In fact, as the attached article from the March - April 1982 issue of

Public Power notes, the title I program has been beneficial in some instances.)

However, the program has accomplished its purpose. Regulatory authorities have reviewed the standards. Determinations as to their appropriateness have been made. Unfortunately, the statute did not contain a sunset provision. This fact alone poses significant problems for public power systems not crossing the sales threshold prior to November 9, 1978. As these systems grow into the program, they are confronted with the problem of how, or whether, to comply, and if compliance is necessary, what is the appropriate time frame. Drafters of the legislation failed to address this problem. Compliance deadlines under section 111, 113, and 114 are all geared to the date of enactment. Standards must be reviewed and other actions taken within two or three years of enactment. But what about systems which cross the sales threshold in 1982 or later? The statute provides no assistance or guidance for these systems.

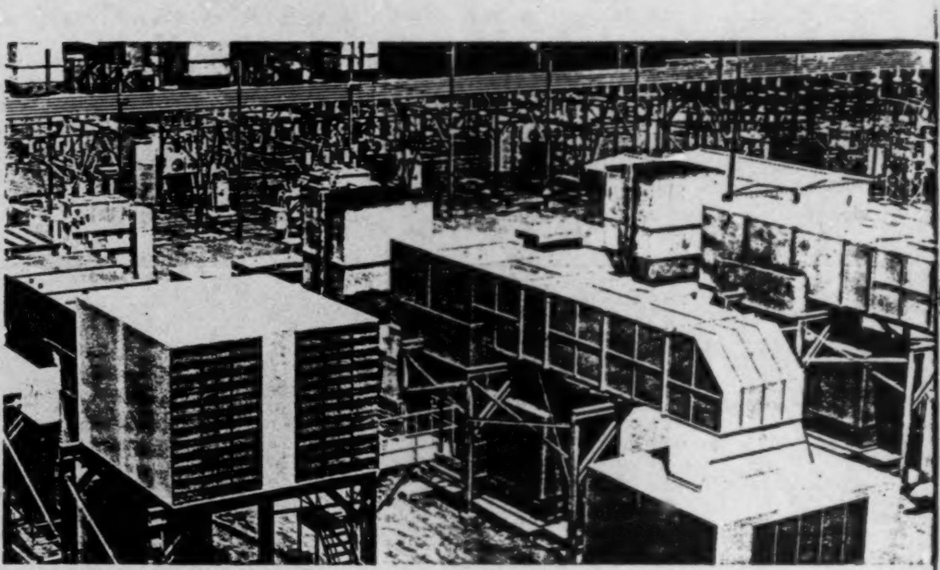
Further, utilities and regulatory authorities are subject to actions requiring a reexamination of various standards during ratemaking proceedings. The harassment opportunities are obvious, and rate proceedings may be delayed pending resolution of the reexamination of the PURPA standards.

Section 133 poses its own unique problems. The cost of complying with these cost of service reporting requirements is extremely high. Public power systems surveyed by APPA estimated that annual costs to comply with the section 133 program could exceed several hundred thousand dollars. As far as we have been able to determine, the information which must be submitted to FERC has not been utilized.

Here, again, utilities and state and local regulatory authorities, may have benefited from the section 133 program. However the benefits have been experienced and it is time for the Congress to eliminate this costly and at this point, unnecessary program.

APPA thus encourages the Subcommittee to consider not only the repeal of section 116 but of all of PURPA Title I.

How PURPA



Fayetteville, N.C.'s eight 25-MW combustion turbines have saved its public power customers more than $4 million since 1976.

THE FAYETTEVILLE (N.C.) Public Works Commission (PWC) was one of the first municipals in the country to meet the stringent data collection and reporting requirements of the Public Utility Regulatory Policies Act (PURPA). Cost of compliance was high. However, we found the act provides major benefits, some of which were not initially apparent.

Our commission serves about 50,000 electric, water and sewerage customers in Fayetteville and outlying areas of Cumberland County. Because PWC delivers more than one billion kWh of energy annually, it was required to make a PURPA Section 133 filing with the Federal Energy Regulatory Commission early last year. We engaged Ebasco Business Consulting Co. to help meet requirements.

Cost-of-service studies have proven their usefulness over the years in designing equitable rates. The study required by PURPA is elaborate in that class costs are required according to demand, energy and customer components on a time-differentiated basis for each major voltage level. Such a study not only provides a means for determining class revenue requirements; it also points to appropriate rate structures within classes, and guides decisions regarding time-of-use (including both time-of-day and seasonal) rates.

The PWC had not previously undertaken cost-of-service analysis of this nature. Had it not been for PURPA we never would have done it in such detail. I still doubt whether the degree of detail required was really necessary. But information the study provided has already been put to good use.

Industry Subsidy Surprising

We learned that our industrial customers' rates were too low and that the commercial class was picking up the slack. Since we are concerned with area development we weren't surprised by this. Surprising, however, was the magnitude of the difference. When we later needed an interim rate increase we raised only the industrial class.

With the costs of power plant construction and general inflation soaring, our baseload power supplier has filed for wholesale rate relief three times in the past three years. Not only have the rates increased dramatically; the rate structure has been changed with each petition. Demand charge increases have far outpaced energy charge increases. The ability of the PWC to pass on these increased wholesale power costs to its customers equitably on a "quick response" basis is improved by our new, sophisticated, easy-to-update method of determining costs.

Time-Differentiated Costs

While our data base was developed to meet the requirements of PURPA, we do not view the outcome merely as a PURPA study. We have taken the position that the burden of PURPA reporting is too heavy to be dismissed as merely a reporting requirement. A data base of this sort can create other benefits besides providing information on system

helped us

by **R.A. MUENCH JR.**
Muench is administrator of the Fayetteville (N.C.) Public Works Commission.

costs. The main value is having useful information regarding time-differentiated costs, but there are other benefits.

- First, having better insight into system load characteristics will enable us to do a better job of using peaking equipment to keep down total power costs. The utility owns eight 25-MW combustion turbines, four of which burn either No. 2 oil or natural gas and four of which burn oil only. We estimate the peakers have saved Fayetteville ratepayers more than $4 million since the first unit became commercial in 1976.
- Second, the time-of-use cost-of-service study which Ebasco performed helps us understand possible advantages and risks of time-of-use pricing. The potential for time-of-day rates was thoroughly evaluated during the course of the hearings on rate standards required by another section of PURPA.

The commission rejected time-of-use rates as a standard, but concluded the rates themselves may be appropriate. The cost-benefit relationship was shown to be marginal at present — the cost of metering 50,000 customers on a time-of-day basis approached the expected system savings under time-of-use rates.

- Third, our new knowledge of class load shapes has enabled us to evaluate potential benefits of load management. Of course, our peaking units provide the best form of load management. However, some additional benefit could be gained from managing our customers' loads. One of these benefits may be compensating for possible "needle-peak" problems which may arise should we go to time-of-use pricing.

R.A. Muench Jr.

- Last, but perhaps most importantly, our improved knowledge of load characteristics helps us plan for future power needs. The utility is considering purchasing ownership in an existing or future plant of its wholesale supplier, Carolina Power and Light Co. It is also considering construction of a coal-fired baseload unit of its own. This scenario would feature sale of parts of the unit to other North Carolina municipals, or a coordinated dispatch agreement with Carolina Power. Several small hydro sites are being studied for economic feasibility and permit availability.

Rationale For Costing

It might seem unusual for a utility which purchases most of its power under a conventional wholesale rate to conduct a time-of-use cost study, but that is exactly what the PWC had to do to comply with PURPA, according to Ebasco consultant John W. Lansing. He was responsible for the accounting cost-of-service work related to PURPA and continues to advise the Fayetteville utility on cost and rate matters.

An accounting (or embedded) cost-of-service study involves collecting utility operation costs over a test year period and assigning those costs first to functions and then to rate classes. In the case of a time-differentiated cost study, costs which vary over time are assigned to periods prior to class allocations according to when they occurred. The costs which are usually associated with time of use are those of production (capital and fuel). For the PWC, another major cost is that of purchased power.

"Although the PWC pays a single monthly demand charge and a flat energy charge for its baseload power, the demand charge is very time-specific," Lansing told us. "In addition, the total energy cost includes not only the flat purchase charge, but fuel burned by the PWC's peakers." (They are also operated on a time-specific basis in order to minimize total power costs.) The relationship of these major components of the PWC's costs of operation to the time of their occurrence leads to the logical choice of a *time-differentiated* embedded cost-of-service study.

Traditional costing theory, according to Lansing, would require that only those who demanded power during the system peak hour should pay fixed costs (the demand charge plus the capital cost of the PWC generation plants) of meeting the peak. This theory is valid in principle, but other considerations are also apparent.

Ebasco's John Lansing describes the rationale behind the time-of-use costing method used in Fayetteville.

The historical PWC monthly peaks have generally occurred in the morning or early evening hours during the winter months, primarily because of electric space heating. The air conditioning load, which reaches its maximum during the late afternoon hours, essentially creates the summer peak. Despite these strong tendencies, the peak for a given month can theoretically occur at any hour. Our consultant said that to properly recognize that uncertainty a probabilistic approach based on expected system load shapes seems to be the appropriate solution.

Aside from PURPA compliance, the main reason for doing a cost of service study is to provide a way to set equitable rates for various classes of customers. Rates are based on a projected test year. Of course, the exact times when future peak loads will occur cannot be known now. But historical tendencies — probabilities — can be used to project future load shapes and peak potentials. ●

SUPPLEMENTAL STATEMENT OF THE AMERICAN PAPER INSTITUTE TO THE SUBCOMMITTEE ON ENERGY REGULATION

Supplementary Statement with Respect to Impact of American Electric Power Case and the Need for Prompt Congressional Action

I appreciate this further opportunity to present to the Senate Subcommittee on Energy Regulation the concerns of the American Paper Institute ("API") on the problems created by the recent decision of the District of Columbia Court of Appeals which struck down two rules of the Federal Energy Regulatory Commission ("FERC"), rules which were having a beneficial effect and were encouraging cogeneration.

My name is William J. Nicholson. My association with Potlatch Corporation and my background are described in my earlier statement. In that statement I also outlined the very strong interest in cogeneration of API and its member companies. The U.S. pulp, paper and paperboard industry is the nation's leader in cogeneration and self-generation -- some 3,000 megawatts -- and has the potential to produce far more if there is an economic incentive to do so. It is this strong interest in cogeneration that prompts this supplemental statement.

In my earlier statement, I referred to American Electric Power Service Corp. v. Federal Energy Regulatory

Commission, No. 80-1789, slip. op. (D.C. Cir., January 22, 1982), rehearing denied, (April 9, 1982) ("AEP"), noting that the case had created further uncertainty as to the economics of cogeneration and small power production, and that it had underlined the need for a reasonably certain and durable economic environment for private power generation.

The court vacated the FERC rules which required that electric utilities pay for cogenerated electricity a rate equal to the utility's avoided costs (i.e., the amount saved by the utility by virtue of having the cogenerated electricity available) and the rule requiring that utilities make available an electrical interconnection to the utility's lines at the cogenerator's expense. Quite plainly these rules were important. Certainly, without an assurance of interconnection, few if any potential private generators are going to make significant investments. Private parties have invested in the past to produce power for their own use where this was economic, and will do so in the future, but the whole purpose of the cogeneration provisions of the Public Utility Regulatory Policies Act of 1978 ("PURPA") was to encourage more cogeneration* than was taking place

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* In the statement I have tried to express our concern as succinctly as possible. References to "cogeneration",

(Cont'd on following page)

before PURPA. Private generation is not going to be encouraged if a private generator cannot get his power onto the utility grid, or if doing so requires time-consuming, unfamiliar or expensive administrative proceedings.

Similarly, the avoided cost rule was designed to elicit more cogeneration than was being developed before PURPA. Prior to PURPA, businesses and individuals would generate power only to the extent they could use the power and if it was significantly cheaper than buying at the average retail rate charged by an electric utility. PURPA set out to change this by providing an incentive to produce the maximum amount of power possible given the cost of alternative power produced by the utility. Under PURPA the FERC was to prescribe and revise such rules as it determined necessary to encourage cogeneration and small power production. (Section 210). PURPA specifies that these rules shall require electric utilities to purchase electricity from cogenerators at rates that are in the public interest, that are just and reasonable to the utility's consumers, and that do not discriminate against cogenerators. This was capped by a requirement that rates for purchases by utilities shall not exceed "the

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(Cont'd from preceding page)

for example, will generally refer equally to small power production. The distinction is significant under the PURPA scheme, but not for my present purposes.

incremental cost to the electric utility of alternative electric energy." In other words, cogeneration was to be encouraged, but cogenerated electricity was not to cost the utility or its customers more than electricity from other sources.* The FERC promulgated a rule setting rates for purchases at this very level -- the utility's avoided cost. This was the second rule stricken by the AEP court.

I will not discuss the merits of the court's ruling -- a matter for the lawyers and judges. I am concerned about the impact.

PURPA was enacted in November, 1978. The FERC's final avoided cost rule came out in May 1980. Until then, those interested in cogeneration were without a sufficiently hard price signal to justify serious planning. Moreover, for heavy industry such as the pulp and paper industry, design and construction are, in most cases, dependent on the plant planning and budgeting cycle. So it was not until after mid-1980 that the new price signal for cogenerated electricity began to be a factor in industry planning. Even then, the process was necessarily a very slow one, because executives who sign off on capital budgets are very hesitant to do so based on unproven economics. The economics were unproven even after the FERC rules were promulgated because state commissions still had to act, and for the prudent businessman there was a further question as to whether the avoided cost rates were really going to materialize. I think it fair to say that it was well into 1981 before most engineering departments were actually starting to consider seriously the economics of the additional cogeneration that could be warranted by the price indicated by the FERC rules. Recall that the pulp and paper industry has always been a cogenerator. Typically, the question now is whether additional expenditures should be made, as plants are updated or new ones built, so as to produce more electricity than would have been justified in the past. Plainly, in this setting, the price paid for new electricity is critical, and will determine the level of investment.

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* The thrust of the PURPA ceiling and the meaning of the term "avoided cost" confirm an essential aspect of the avoided cost rule -- the rate paid cannot be such as to impose added costs upon the utility customers. The price paid the cogenerator can be no greater than the amount the utility would have paid without the cogeneration. We in the pulp and paper industry are major utility customers -- our 1981 bill for purchased power was $1.8 billion -- and we would not support a rule that would increase this already staggering bill. The essential element of the rules is that cogeneration is encouraged without increasing retail power rates.

You can see that, in January 1982, the AEP decision came at a critical time -- just as engineering departments were getting serious, just as state rules were being ironed out. Some 34 states have cogeneration rules in effect now or have issued proposed rules. Add to this the prevailing and unavoidable uncertainty about the future price of fuel generally, and it is plain that in the wake of AEP, few businessmen are going to make the incremental investments that PURPA was designed to encourage. What is again missing, as it was prior to PURPA, is a price signal that will be reasonably durable and certain.

Moreover, I believe this signal is needed soon. If there is a substantial period of uncertainty, plant designs are going to revert to pre-PURPA criteria, and once again industry's economic cogeneration potential will not be made available to the nation.

Bear in mind that even with the avoided cost and interconnection rules in effect there are plenty of hurdles for cogenerators. Across the country utilities have resisted contracting with cogenerators. (It was, of course, utilities that brought the AEP case that upset the rules.) As noted, some state commissions have rules in place, but for the most part these leave the larger cogenerators to negotiate directly with the utility -- which, typically, was unenthusiastic before AEP, and is even less so now. State commissions are stymied, especially in the majority of states where commissions do not have independent statutes to set rates for cogenerated power. In some states the commissions have authority under state law, but, encouraged by the AEP decision, this authority is being challenged by utilities. In those cases where commissions have said they will force a contract if the cogenerator and utility cannot agree, AEP again looms large because with the avoided cost rule now uncertain, it is difficult to establish the prime contract element -- the price.

The result of AEP is to put state commissions -- many of which have small and overextended staffs -- in the especially difficult position of trying to resolve questions such as federal preemption and commission authority under state statutes before they can get on with the business of getting cogeneration into place. Over this also looms the likely prospect of judicial appeal of any commission action favoring cogeneration. It is an altogether disheartening situation for all but the most determined potential private generator.

So far I have directed my comments principally to the question of price. However, the Court of Appeals' vacation of the FERC's rule allowing cogenerators to obtain interconnection with utilities without submitting to the elaborate adjudicatory procedures established by Sections 210 and 212 of the Federal Power Act ("FPA") is troublesome too. Under the court's interpretation of PURPA and the FPA, the FERC could order interconnection only after conducting a full evidentiary hearing and finding that the interconnection would meet the guidelines set forth in FPA §§ 210 and 212.*

If the AEP decision on interconnection is allowed to stand, a serious blow will have been struck to the prospects for substantial new development of industrial cogeneration. Interconnection with the utility grid is, of course, vitally important to cogenerators. The economic feasibility of most new projects is dependent on being able to sell the power generated by the facility to a utility at the full avoided cost rate. Some cogeneration projects which do not generate enough electricity to meet plant demand will have to purchase supplementary power. Moreover, even the most efficient and reliable plants will need back-up or maintenance power from time to time.

That many cogeneration projects will be installed at existing plants which are already interconnected with their local utility for the purpose of purchasing power may not diminish the importance of the interconnection issue. At least one utility, Consolidated Edison Company of New York, has repeatedly argued that interconnection for the purpose of selling power to the utility is a different matter from interconnection for the purpose of taking retail service. Con Edison insists that a cogenerator must obtain an FPA interconnection order to conduct sales even where it is already physically interconnected for a two-way flow of electricity. While API does not concede this point, intransigent utilities will undoubtedly urge this position on their state utility commissions and further litigation and uncertainty will be the inevitable result. This litigation and delay will introduce substantial legal and administrative costs which industrial developers simply cannot afford if their projects are to be cost-effective by corporate standards. Thus, as matters now stand, any cogenerator or small power producer may have to face the hurdle of Sections 210 and 212 of the FPA in order to sell its power generation. At the very least, they face the burden of persuading the state commission and the utility that these rules do not apply -- a major obstacle.

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* The court suggested that the FERC might be able to adopt streamlined procedures under FPA §§ 210 and 212 to simplify and speed the interconnection process. There appears to be no way around FPA § 210's evidentiary hearing requirement, however, which drastically limits the extent to which streamlining is feasible.

Since the enactment in 1978 of Sections 210 and 212, the FERC has successfully conducted only one proceeding under them and that proceeding took more than 2-1/2 years to complete. Compelling the FERC to conduct hundreds of such proceedings will create a regulatory morass from which many projects may never emerge.

At least as important, many potential cogenerators and small power producers will be discouraged, intimidated or frustrated by the prospect of interminable administrative wrangling and will simply forego projects they would otherwise have undertaken.

What is most distressing to us about this scenario is that it is both unjustifiable and unnecessary in light of the policies underlying PURPA § 210 and FPA §§ 210 and 212. In PURPA § 210, Congress spelled out its intent to relieve cogenerators and small power producers from as much of the burden of government regulation as was feasible and consistent with the public interest. The public interest cannot be served, however, by regulation so burdensome that it discourages cogeneration, especially where Congress has expressly acted to encourage that activity as they did in Section 210 of PURPA.

Similarly, the standards of Sections 210 and 212 of the FPA, which the FERC must observe in ordering interconnection under those provisions, are aimed at protecting the public interest and improving the efficiency and reliability of the nation's electric generation system without unduly burdening electric utilities. Again, by enacting Section 210 of PURPA, Congress has already expressed its sense that adding as much cogeneration and small power production to the utility grid as is economically feasible is consistent with these aims.

Some might argue that federal action on the interconnection issue is not necessary because individual states have almost universally provided for mandatory interconnection in their own rules implementing PURPA § 210 and the FERC rules. These states seem to be standing fast by their interconnection rules in the face of the AEP decision, for which API applauds them. Utilities have argued, however, that the FPA preempts state prerogatives in this area and that without an affirmative grant of power by Congress to the states, the states are powerless to adopt and enforce such rules. API disagrees vehemently with this analysis, but the merits of the legal question are of less importance than the uncertainty created by the unsettled state of the law. I cannot urge strongly enough the need for an unequivocal direction from Congress that mandatory interconnection of cogenerators to the utility grid is consistent with the public interest and necessary for the effective development of the nation's cogeneration and small power production potential.

It should be plain from what I have said that the FERC rules have been an important force encouraging cogeneration. They were starting to produce the results Congress wanted. The state commissions liked the FERC rules. In fact, in many cases the states adopted or substantially adopted the FERC rules as their own. No state has expressed reservations about the avoided cost rule, for example, and no state has sought an exemption from the FERC rules -- a procedure specifically provided for. The FERC/state rules were designed to be, and were becoming, the starting point for major cogeneration projects. The rules, especially the avoided cost rule, were the basis for negotiations between utilities and private generators. As discussed in detail in my earlier testimony, in many if not most cases, contracts would be negotiated at a price below avoided cost*, but it is the presence of the avoided cost rule that permits a commission to force a contract at a reasonable price if the parties cannot agree.

The bottom line is that the entire PURPA § 210 scheme is seriously threatened by the AEP decision. API urges that

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* Note that for this reason, setting the rate for utility purchases at, say, 80% of full avoided cost may in fact penalize the utility's ratepaying customers. If the purchase rate is set arbitrarily low, significant amounts of cogeneration will not be built. However, the utility will still have to supply the power which would have been displaced by cogeneration, and, by definition, the cost of that power (to be passed on to the ratepayer) is the utility's full avoided cost. The utility will have saved some money on its payments to cogenerators, but will have cost its ratepayers that much and more because of the differential between full avoided cost and what the contract purchase rate would have been under the original FERC rules.

Congress take action as soon as possible to rectify the damage caused by that case.

Given the current state of affairs -- the AEP decision and the hostility of many utilities to purchasing power from industry -- much cogeneration appears to be stymied for some years to come. Congress can and should resolve this situation. It can pass legislation embodying the substance of the existing FERC rules regarding interconnection and avoided cost. You will note that I have stressed the phrase "existing FERC rules". This is because if Congress enacts different legislation it will probably cause a period of delay while FERC and the states amend their existing rules in long rulemaking proceedings. Such a procedure necessitated by slight changes could put cogeneration on hold for two years or more.*

It is pertinent to note again that not a single state has asked the FERC for a waiver to deviate from the framework of their rules. State commissions have supported the FERC rules and in many cases have decided that it was in the interests of their ratepayers to go beyond the bounds required by FERC.

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* It took the FERC 15 months to implement § 210 and today, two years later, many states still have not finalized their rules.

STATE OF ARKANSAS
OFFICE OF THE ATTORNEY GENERAL
JUSTICE BUILDING, LITTLE ROCK 72201

STEVE CLARK
ATTORNEY GENERAL

(501) 371-2007

April 15, 1982

The Honorable Gordon J. Humphrey, Chairman
Subcommittee on Energy Regulation
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Senator Humphrey:

On April 19, the Senate Subcommittee on Energy Regulation will be conducting hearings to consider S.1885. On behalf of the Arkansas Attorney General, I hereby request that the attached comments be included in the record of the hearing.

Sincerely,

MARY STALLCUP
Deputy Attorney General

Enclosure

MS:pw

cc: The Honorable Dale Bumpers
The Honorable Howard M. Metzenbaum

COMMENTS OF THE ARKANSAS
ATTORNEY GENERAL
CONCERNING S.1885

SUBMITTED TO THE
SENATE SUBCOMMITTEE ON ENERGY REGULATION

BY
ATTORNEY GENERAL STEVE CLARK

APRIL 15, 1982

S.1885 will provide additional encouragement for electric utilities to invest in cogeneration. However, one must remember that the development of cogeneration is not an end in itself, but rather a means to an end; that end being the most efficient and economical use of our resources. The welfare of the utility ratepayers must not be neglected lest the benefits of cogeneration be lost. The following comments will explain that the additional incentives proposed in S.1885 will encourage cogeneration only at the expense of the electric utility ratepayers.

Since S.1885 would extend to utilities all the benefits provided to qualifying facilities by FERC Order 69, ostensibly this bill would allow a cogeneration facility that is 100% owned by an electric utility to become a qualified facility. That facility would thus be entitled to (1) receive full avoided costs;[1] (2) receive additional tax benefits under the Energy Tax Act of 1978;[2] and (3) operate without the constraints of regulation[3] (at least with respect to the rate of return).

The most important benefit to the utility, and the most detrimental to its ratepayers, is the payment of avoided costs to a utility-owned qualifying facility. We believe that an understanding of the issues involved--avoided cost, least cost of service obligations, the intent of FERC Final Rules--will lead to the conclusion that payment of avoided cost to a utility owned cogenerator cannot be in the public interest. In fact, we would submit that even the presently allowed 50% level of ownership should not permit a utility to pay itself avoided cost. Yet the FERC final rules regarding qualifying status and ownership criteria (§292.206, Docket RM-79-54) would allow this.

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[1] §292.304(a) of FERC Order No. 69, Docket RM-79-55.

[2] See "Tax Issues," discussion of §292.304 of FERC Order No. 69; 45 Federal Register 12228 (February 25, 1980).

[3] §292.601, §202.602

We do not oppose utility development of cogeneration, nor some incentive to encourage such utility participation. But the incentives should be within the context of its franchised, regulated operations, such as tax benefits or higher allowed return on equity. The utility has a duty to provide electric service to its customers at the least cost of service. If developing cogeneration is less expensive for ratepayers than constructing traditional power plants, then the utility is obligated to invest in cogeneration as a part of its regulated operations.

We are at a loss to understand why cogeneration should be treated differently from other utility alternatives, such as air conditioning switches, other load management programs, conservation financing or even building power plants. There is no reason that cogeneration should not also become an integral part of system operations and planning. If cogeneration is not the most economical alternative, the utility and the ratepayers would be better off by foregoing that investment.

To subsidize the utility simply for the sake of developing cogeneration is unfair to the ratepayers.

If a State Commission deems it economical for a utility to invest in cogeneration, as it almost certainly will, and that additional incentive is necessary, then the Commission can increase the allowed return on equity for the investment, or permit parts of the steam function to be included in the rate base. The individual State Commissions are in a better position to evaluate the need and desirability of utility participation in specific cogeneration projects. They are likewise in a better position to identify the specific incentives that are required without creating an environment in which utility stockholders are subsidized by the ratepayers. The payment of avoided cost to utility owned cogenerator will result in such subsidization and will create a serious conflict for the utilities between the obligation of least cost service and encouragement of cogeneration.

The problems and conflicts that arise when a utility is both buyer and seller in the same market already exist, but passage of HR 2876 will greatly exacerbate the problems and potentially create new ones.[4] Before explaining the conflict that arises when a utility pays itself avoided costs we would like to briefly discuss several of the issues surrounding cogeneration and utility treatment of it.

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[4] The new problems arise when the utility begins forming unregulated or partially regulated subsidiaries. There are already problems of jurisdictional gaps in which no oversight is exercised.

In its final order the FERC rules that the amount which should be paid a cogenerator is the utility's "avoided costs." That is, the costs the utility would otherwise incur producing electricity if it did not receive it from a cogenerator. At any time, the utility that operates under economic dispatch will avoid the fuel and variable costs of running the least efficient plant that is on line. These are the incremental, or marginal energy costs. There are also potentially avoidable capacity costs in most instances, but I will defer comment on this somewhat controversial issue. The minimum rate to be paid a cogenerator for electricity supplied is the avoided energy costs.

The avoided energy costs for most--though not all--utilities in the country are quite high because they have a suboptimal generation mix. The utilities are generally highly dependent upon oil and gas-fired capacity, the result of investment decisions made in the sixties and seventies. Because the escalation of oil prices has been so dramatic the utilities are now in the process of improving their generation mix by adding coal and nuclear capacity. But a utility is never at the optimal mix for long; it must be cognizant of constantly changing circumstances to make plans to move toward optimization. It must plan for the appropriate size, fuel type and design of new plants and for purchased power contracts, all of which affect the avoided cost of the utility. These plans require decisions by the managers and stockholders of the utility. To summarize, the avoided costs of a utility are a function of the current generation mix of the utility. The generation mix is ultimately the result of investment decisions made by the utility's managers and stockholders. So, effectively the stockholders can control the avoided costs of the utility.

This leads directly to the conflict that arises when a utility pays itself avoided costs. We suggest that the intent of the utilities is to set up a wholly owned subsidiary that is primarily involved in cogeneration. The utility would then make payments to its own subsidiary.[5] It is important to remember, however, that the stockholders of the utility and the subsidiary are the same.

The Commission recognized the natural monopsony position of the utility's transmission and distribution system and therefore required the utility to purchase all offered cogenerated power and energy. Since a cogenerator is not subject to state and federal regulations, at least with regard to the return on his investment, and he is assured of a market for his electric sales, there are essentially two factors that affect his return. One is the level of generation he can achieve; that, in turn is dependent upon the level of investment in cogeneration. The second is the price he will be paid, i.e. avoided costs.

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[5] The subsidiary would be necessary for the other benefits as well, i.e. the utility would need to totally separate the operations to avoid regulation of the operations. The subsidiary could also use the tax credits whereas some utilities have used up all tax benefits for some years into the future.

Let's now look at the utility and the utility's cogeneration subsidiary from the perspective of the stockholder. They have two choices with respect to where they will invest their money: in the utility or in the subsidiary. If the stockholders decide that investments should go to the utility, several things occur; first, the investment will presumably improve the utility's generation mix, thereby lowering the avoided costs. The return on that investment is fixed by the regulatory authority. Second, the lower avoided costs resulting from the investment will affect (reduce) the return that the unregulated cogeneration subsidiary will make.

If the stockholders investments are allocated to the cogeneration subsidiary, to the neglect of the utility, they are simultaneously increasing the amount of electricity produced by the subsidiary and assuring that the sales price for that electricity is maintained at a high level. Thus, since the return of the subsidiary is unregulated, investing in the subsidiary and ignoring the regulated utility will be much more profitable to the stockholders than investments in the utility. Ratepayers can suffer if the stockholders make decisions based purely on self-interest.

It is, of course, probable that investments will be made in both the utility and the subsidiary. But the capital market is highly competitive and a company's ability to raise capital is limited. Given that situation it seems clear that the priority of investments would be altered biased toward the subsidiary, to the detriment of the ratepayers.

The utilities have argued that the cogeneration market is limited by the areas' steam and process heat demands. Thus, the utility's conflict of interest just described would be minimized. This is simply not the case.

But there are also other, long range ramifications that should be considered. First and foremost it must be recognized that even if the cogeneration market is saturated -- i.e. the cogeneration potential is exhausted -- the utility's subsidiary would still benefit even if the utility simply chose not to invest in new capacity. That is, the conflict doesn't disappear simply because the amount of electricity produced by the subsidiary is not expanding. It exists as long as the control over the avoided costs remains with those who have a vested interest in the profit of the cogeneration subsidiary.

Beyond that, it is unlikely that the cogeneration potential will ever be exhausted. Arkansas Power and Light is active with our State's Industrial Development Commission in attracting new industry to Arkansas. Also, as the technology develops more and more projects will become feasible: cogeneration for apartment complexes, commercial buildings, new industrial parks, universities,[6] brick manufacturers, etc.

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[6] Arkansas currently has a solar powered community college that will soon make use of photovoltaics to produce electricity.

Small power production will also expand: such as farmers cooperatives pooling their agricultural wastes to produce electricity,[7] municipalities using methane from sewage treatment plants in generators, lumber yards and timber companies using wood wastes to fuel electric generators. Of course the utility will not own or control all of this as it develops, but to the extent that it owns _any_ the conflict of interest will persist and grow.

Another interesting problem could arise in the future, especially in the densely populated areas of the northeast. What if it becomes practical, or even necessary, given stringent siting laws, to follow the European trend of district heating? This is a process of piping the waste heat of base-load plants (about 67% of all the energy used at the plant) to residential areas for water and space heating. This is cogeneration as much as building a combined cycle cogenerator at an aluminum plant. Surely, a utility owned nuclear plant could not become a qualifying facility!? But the proposal before this Committee would do just that.

Up till now we have discussed avoided costs in terms of energy costs. We have done so because we perceive the problems to be most acute in this area and because capacity payments are offered by very few utilities at present. However, given the nature of the conflict of interest we have described above, the potential problems of avoided capacity costs may be just as great.

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[7] Riceland Foods currently cogenerates using rice hulls as the fuel source.

Avoided capacity costs, as established by FERC and refined by the Economic Regulatory Administration, would occur when cogenerated capacity of sufficient reliability is provided such that the utility can avoid constructing new capacity, defer the construction of new capacity, build a smaller plant or sell some of its existing capacity (if the utility is already in excess capacity position). Currently there are very few utilities, if any, offering avoided capacity costs to cogenerators. If utilities become entitled to full avoided cost payments, that situation could easily change.

Given the existing incentives provided for cogenerators one could expect most third party cogenerators[8] and perhaps even some industrial cogenerators to attempt to optimize the electric generating function--rather than having electric output dependent solely upon current steam needs. This would almost certainly be the case for a utility owned cogeneration subsidiary. In such a situation the power from the cogenerator would be of sufficient reliability to allow the utility to avoid some capacity costs, in the sense mentioned above. The danger would then exist of the utility fabricating various expansion plans that could then be "avoided," allowing its subsidiary to receive capacity payments based on the expansion plan.

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[8] A third party cogenerator would be a company who exists solely for the purpose of cogenerating: selling steam to industry and electricity to the utility.

We do not contend that EEI and the utilities are supporting S.1885 (and the companion bill, H.R.2876) with such plans in mind. We doubt that they have given the prospects that much consideration. But the incentives and the opportunity to engage in such activities will exist if this proposal is enacted into law.

The additional incentives for utility investment in cogeneration provided by S.1885 are not only undesirable, they are wholly unnecessary. Electric utilities already have the duty to invest in cogeneration if the investment will result in lowest cost electric service to ratepayers. If such a project involves higher risk than a traditional generating unit, this fact will be considered by state regulatory commissions in setting the utility's rate of return. Utilities should not be allowed unregulated profits on cogeneration investments which they are required to make within the context of their regulated operations.

The direct impact this legislation would have in terms of the cost to ratepayers is severe. Perhaps more important, however, is the precedent that this Act would set: allowing a regulated utility to externalize a key function of its operations in order to maximize its return. In this instance cogeneration and small power production[9] are being externalized.

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[9] If a utility began using alcohol fuel in a peaking unit, which is highly feasible given the forecast price for natural gas in 1985, that unit could also become a qualifying facility.

Will generation, transmission and distribution be separated and externalized next? This Committee is faced with an extremely important decision regarding where the line must be drawn with respect to which operations a utility should be allowed to externalize and which rightfully belong with the utility. There are perhaps some functions of a utility's operations that could be externalized and deregulated with no adverse effect--such as conservation financing, solar heating installations or energy management systems--but the production of electricity is not one of them. That is, after all, what they are in business to do.

ELCON

STATEMENT OF THE
ELECTRICITY CONSUMERS RESOURCE COUNCIL
TO THE SUBCOMMITTEE ON ENERGY REGULATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
REGARDING S. 1966 AND S. 1885

The Electricity Consumers Resource Council (ELCON) is pleased to submit the following statement regarding two bills — S. 1966 and S. 1885. S. 1966 would amend the Public Utility Regulatory Policies Act (PURPA) to eliminate paperwork and reporting requirements under Section 116 of that Act. S. 1885 would remove the 50 percent restriction on utility ownership of qualifying cogeneration facilities (QF's).

ELCON is a group of seventeen large industrial consumers of electricity with facilities in most of the fifty states.*/ ELCON advocates and promotes the development and adoption of coordinated, rational, and consistent federal, state, and local policies which will assure an adequate, reliable, and efficient electricity supply for all users at prices based on the costs incurred in serving customers.

ELCON's members consume approximately ten percent of all electricity sold to industrial customers and nearly five percent of all electricity sold in the U.S. Because of our members' use of electricity, ELCON has a significant, continuing interest in the electric utility industry, and we appreciate the opportunity to comment on this legislation.

Summary and Recommendations

First, ELCON supports S. 1966. In fact, ELCON has recommended that all of Title I of PURPA be repealed.

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*/ ELCON members are: Air Products and Chemicals, Inc.; Airco, Inc.; Anheuser-Busch Companies, Inc.; Armco; Bethlehem Steel Corporation; Diamond Shamrock Corporation; E.I. du Pont de Nemours & Company; FMC Corporation; General Motors Corporation; Kaiser Aluminum & Chemical Corporation; LCP Chemicals & Plastics, Inc.; Nabisco, Inc.; Olin Corporation; PPG Industries, Inc.; Stauffer Chemical Company; Union Carbide Corporation; and United States Steel Corporation.

Second, ELCON believes that the development of cogeneration by both industrial firms and utilities should not be discouraged where such facilities can be appropriately utilized. Some utilities contend that the existing 50 percent utility ownership restriction discourages utility development of cogeneration. However, for reasons discussed later in this statement, we are concerned that the effectiveness of public utility regulation could be diminished if the 50 percent cap is removed as proposed in S. 1885.

ELCON thus opposes S. 1885 as it is currently written.

Our opposition to S. 1885 does not mean that we are opposed to utilities owning cogeneration facilities. Utilities can and do own such facilities. Rather, we are opposed to legislation that would allow utilities to establish unregulated cogeneration facilities until two areas of concern have been addressed.

First, Federal Energy Regulatory Commission (FERC) Chairman C.M. Butler testified before this subcommittee that he disagrees with the present FERC legal conclusion that "companies affiliated with utilities cannot qualify for the benefits of Section 210 of PURPA." This issue is being studied by the FERC, and new rules may be proposed. ELCON believes it premature to support legislation until FERC concludes its study and rulemaking.

Second, ELCON is concerned that total removal of the 50 percent ownership cap without any regulatory oversight of utility-owned facilities could give utilities an unfair advantage relative to industrial cogenerators because of the serious legal doubts already existing about key provisions (e.g., interconnections) of the FERC rules implementing PURPA Section 210. Additionally, total removal could induce some utilities to put their scarce investment dollars in unregulated, cogeneration facilities rather than make needed long-term capacity investments in their regulated facilities. In ELCON's view, neither outcome is in the interest of existing ratepayers — residential, commercial, or industrial.

PURPA stimulated the development of cogeneration by reducing obstacles facing prospective industrial cogenerators. ELCON is concerned that removal of the 50 percent cap could reduce the ability of industry to take advantage of the PURPA provisions. Thus, although ELCON cannot support S. 1885 as it is currently written, we could support proposed legislative or regulatory changes that would have the clear, unambiguous effect of:

1. Providing that the same interconnection criteria are applicable to both utility and industrial QF's and that QF's (of 1 MW or more) are guaranteed an interconnection as a matter of law.
2. Providing that utility and industrial QF's are treated equally with regard to the calculation and application of avoided cost, backup and maintenance rates.
3. Retaining the existing rules on QF buy/sell arrangements.
4. Providing that no existing utility facility could be designated a QF. The waiver of the 50 percent rule would apply only to facilities coming on line in their entirety after the enactment of this legislation.
5. Providing that utility-owned QF's must on request supply the data and records to regulatory authorities necessary to assure adequate protection of the utility's customers.

Whatever the resolution of the 50 percent cap ownership issue, ELCON recommends that utilities be allowed to benefit from certain incentives presently granted only to industrial cogenerators. Specifically, utility and industrial cogenerators should be treated equally with regard to energy tax credits.

Background

Prior to the enactment of PURPA, a prospective industrial cogenerator faced three major obstacles. First, utilities were often unwilling to purchase power at all or were willing to purchase such power only at unreasonably low rates. Second, some utilities charged discriminatorily high rates for backup service. Third, a cogenerator which provided electricity to a utility could be considered a public utility and, as such, might be subject to extensive state and Federal regulation.

Congress passed PURPA as part of the National Energy Act of 1978. Sections 201 and 210 of PURPA were intended to encourage the development of industrial cogeneration by reducing legal, regulatory, and institutional barriers.*/ These sections were implemented by the FERC so as to specifically limit "qualifying status" to those cogeneration facilities that were less than 50 percent utility-owned. Congress did not intend to discourage the development of utility cogeneration; the statement of managers accompanying the bill states:

> It is also the intention of the conferees that the definitions of "qualifying cogeneration facility" ... will not be construed as prohibiting or discouraging electric utilities from cogenerating.

Thus, it is important to note that Congress did not intend to encourage, nor discourage, utility development of cogeneration.

FERC rules promulgated under PURPA provide certain incentives to QF's. These incentives: (a) grant QF's the right to interconnect with utilities without meeting the full requirements of the Federal Power Act

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*/ These ELCON comments relate only to cogeneration facilities although we recognize that PURPA was intended to promote both cogeneration and small power production.

(FPA); (b) require public utilities to offer to purchase available electric energy from QF's at the utility's full avoided cost; (c) require utilities to provide backup power and other services (e.g., maintenance power) to QF's on a nondiscriminatory cost-of-service basis; and (d) allow the FERC to exempt QF's from PUHCA, and state laws and regulations regarding rates and the financial or organizational regulation of electric utilities. Additionally, certain tax benefits offered under the Energy Tax Act and the Windfall Profits Tax Act are available only to "qualifying" cogenerators.

Utilities argue that the PURPA 50 percent ownership restriction acts as a disincentive to cogeneration investment by utilities. They also assert that while the incentives provided by PURPA may induce large industrial firms to develop cogeneration potentials available to them, small firms may encounter difficulties in securing adequate financing, assuming the additional risk associated with a new venture, or devoting the necessary management resources required to bring the facility on line. Utilities state that they have the necessary resources and expertise and would establish cogeneration facilities for small industrial customers if the 50 percent cap were removed.

In summary, as long as the recent court decision is upheld, utilities have regained the monopoly advantages that they held prior to PURPA.*/ They seek through this legislation to obtain the advantages that Congress intended to give to nonutility cogenerators.

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*/ On January 22, 1982, the U.S. Court of Appeals for the District of Columbia issued an opinion remanding the FERC's cogeneration rules to the Commission with instructions to reexamine two provisions. (American Electric Power Service Corporation v. FERC, No. 80-1789, D.C. Cir., January 22, 1982.) First, the court ordered the FERC to state more completely the reasons for ordering payments of full avoided cost. The court suggested that the FERC look at ranges (e.g., 80-100% of full avoided cost). Second, the court stated that the FERC cannot exempt cogenerators from possibly complex and time consuming FPA procedures on interconnections.

In testimony presented to this subcommittee on April 19, 1982, FERC Chairman C.M. Butler stated that there is no explicit statutory preclusion to companies affiliated with utilities qualifying for the benefits of Section 210 of PURPA.*/ He stated that at the time the FERC rules were issued, the Commission apparently took the view that such an ownership cap was implicitly required by PURPA, although the Commission provided virtually no rationale for denying "qualification" to companies affiliated with, and thus controlled by, public utilities. Chairman Butler said that he has directed the FERC staff to conduct a study of both the emerging contractual relationships between electric utilities and QF's and the issues that would be posed by allowing utility-affiliated facilities to qualify for the benefits of Section 210 of PURPA. He concluded: "It is my hope that at an early point this study can be converted into a rulemaking proceeding that can deal concretely with these issues."**/

Discussion

S. 1885 has two stated objectives: (1) to enhance the financial health of electric utilities and (2) to encourage cogeneration. Each are discussed in turn.

1. The Financial Health of Utilities

The ELCON member companies recognize that utilities are in uncertain financial health at this time. However, ELCON does not believe that the financial performance of many utilities in the 1970's constitutes a compelling reason to encourage utilities to diversify into cogeneration through the removal of the ownership cap. First, utility financial data now show marked improvement. For example, utilities' actual earned return on equity averaged 12.6 percent in 1981 — significantly higher than the 10.6 percent level of 1974.*/ Similarly, the authorized rate of return has increased from approximately 12.5 percent in 1974 to over 15 percent in 1981. State regulatory authorities granted rate increases of $8.34 billion in 1981 and $5.94 billion in 1980 — a substantial increase over the $1.9 billion granted in 1977 or the $2.2 billion granted in 1978 even when these earlier figures are adjusted to account for inflation.

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*/ Statement of C.M. Butler, III, Chairman, Federal Energy Regulatory Commission, before the Subcommittee on Energy Regulation, Committee on Energy and Natural Resources, U.S. Senate, April 19, 1982.

**/ Ibid., page 11.

Secondly, utilities do not have financial problems because they are prohibited from owning QF's. Particular utilities have financial problems for a variety of reasons including inflation, high interest rates, rapidly rising construction costs, and regulatory actions that do not allow them even the opportunity to earn an adequate rate of return.**/ Encouraging utilities to diversify into cogeneration, particularly when their financial and managerial resources are limited, is not an appropriate means to restore their financial health. This is particularly true when such a strategy avoids a confrontation with the real problem — a failure of regulatory processes to allow utilities an opportunity to earn an adequate rate of return.

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*/ The figures quoted in this paragraph are from remarks of William McCollam, Jr., President, Edison Electric Institute, before the New York Society of Security Analysts, February 17, 1982.

**/ We draw a sharp distinction between being allowed the opportunity to earn and actually earning an adequate rate of return. ELCON believes utilities should be allowed the opportunity to earn (but not be guaranteed) an adequate rate of return.

2. The Encouragement of Cogeneration

Cogeneration is not new, but it has recently become a fashionable way to describe an old process. Cogeneration is the sequential production of electrical or mechanical power and useful heat from the same primary energy source or fuel. Industrial firms (including many ELCON member companies) presently cogenerate and have done so for many years. When used appropriately, cogeneration recovers nearly twice the amount of useful work out of the the fuel used when compared to conventional generation of electricity.*/ There is no doubt that cogeneration is a sound process.

Estimates of the magnitude of the potential demand for cogenerated steam vary, but we are not convinced that the potential for additional cogeneration facilities is great, whether they are industrial or utility-owned. Cogeneration only makes sense when steam demand is located close enough to the cogeneration facility so that the steam can be transported economically. Few, if any, unsatisfied, large steam loads exist that have a potential to be served by cogeneration facilities. (For example, proposals to sell large amounts of steam for district heating often ignore the fact that the poor load factor associated with this type of cogeneration frequently renders its operation uneconomical, to say nothing of the fact that people dislike living near powerplants.) Utilities might create industrial parks where the sum of several smaller steam loads might equal the output of an efficient cogeneration unit. However, a utility would find it very difficult to coordinate the construction of several industrial facilities and the cogeneration facility;*/ the efficiencies of cogeneration may be lost if the construction of the facilities is not coordinated since the balance of steam load and electric generation is the key to greater efficiency.

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*/ We emphasize that the efficiency gains from cogeneration only accrue when there is a need for both the thermal and mechanical energy. A "cogeneration" facility will be less efficient than a conventional generation facility if the steam load does not materialize or materializes but is not utilized.

Utilities are not prohibited by existing law from entering the cogeneration business. In fact, utilities may be 100 percent owners of cogeneration (although not "qualifying") facilities. If there is a market for the output of cogeneration facilities, utilities should already be finding ways to satisfy it. More to the point, we think that utilities have an obligation to install the most efficient facilities and regulators have the responsibility to see that utilities plan and build systems that will meet their customers' needs most efficiently. Although granting QF status to utility-owned facilities may increase a utility's interest in developing cogeneration, ELCON views the lack of significant utility cogeneration at present as further indication that the market is limited.

But regardless of whether the market for new cogeneration facilities is large or not, we are concerned that the unregulated development of cogeneration facilities by regulated electric utilities may harm the utility's customers in one or more of the following ways:

(1) The incentive to reduce avoided costs may be reduced.

(2) The incentive to install an optimal generation mix may be reduced.

(3) Unregulated cogenerators may divert capital and managerial resources from necessary utility functions to unregulated operations.

(4) The implementation of industrial cogeneration may be precluded by utilities granting preferential treatment to utility-owned (relative to industrial-owned) facilities.

(5) The effectiveness of state regulatory commissions may be impaired as utilities remove generating facilities from their jurisdiction.

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*/ Few utilities construct their own facilities. Rather, they use contractors and oversee the project development.

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*NOT ADMITTED IN THE DISTRICT OF COLUMBIA

April 12, 1982

RECEIVED
SENATOR GORDON J. HUMPHREY
1982 APR 15 AM 9 18

Honorable Gordon J. Humphrey
Chairman, United States Senate
Energy Committee
Subcommittee on Energy Regulation
6205 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Humphrey:

On behalf of the Nebraska Public Power District (the District), which provides electricity directly to over 105,000 customers in the State of Nebraska, we respectfully request that the Subcommittee on Energy Regulation include this letter and enclosed comments in the official record of the Committee's hearing scheduled for April 19, 1982 on S. 1966, a bill to repeal Section 116 of the Public Utility Regulatory Policies Act (PURPA).

The District strongly supports this legislation to eliminate an unnecessary and burdensome reporting requirement and urges its prompt enactment. The enclosed comments filed by the District in a proceeding before the Federal Energy Regulatory Commission which focuses on Section 133, the PURPA cost-of-service reporting requirements apply with equal force to the reporting requirements of Section 116.

Thank you in advance for your consideration of the views of the Nebraska Public Power District.

Sincerely,

Karen Hastie Williams

Karen Hastie Williams
Attorney for Nebraska Public
Power District

Enclosures

cc: The Honorable Jack Danforth
All Members of Senate Subcommittee on
Energy Regulation
All Members of Nebraska Congressional
Delegation

DEPARTMENT OF ENERGY
BEFORE THE
Federal Energy Regulatory Commission
WASHINGTON, D.C.

Collection of Cost of Service Information Under Section 133 of the Public Utility Regulatory Policies Act of 1978	)	Docket No. RM82-13

COMMENTS OF NEBRASKA PUBLIC POWER DISTRICT IN RESPONSE TO NOTICE OF INQUIRY

In accordance with the January 29, 1982, Notice of Inquiry issued in this docket, the Nebraska Public Power District (District) submits the following comments:

I.

Copies of all orders, pleadings, comments or other documents filed in this proceeding should be served on the District by service to:

Gene D. Watson
General Counsel
Nebraska Public Power District
Post Office Box 499
Columbus, Nebraska 68601

Dana Contratto, Esquire
Karen Hastie Williams, Esquire
Crowell & Moring
Suite 1200
1100 Connecticut Avenue, N. W.
Washington, D.C. 20036

II.

The District is a political subdivision of the State of Nebraska. Control of the District and its operations is vested in an 11 member Board of Directors popularly elected for six year terms from geographic units comprising subdivisions of the District's chartered territory. The powers exercised by the District are conferred by State statutes enacted by the Nebraska legislature. This District provides firm utility service to approximately 105,000 retail and 100 wholesale customers with the retail customers accounting for about 30 percent of sales and wholesale customers accounting for the remaining 70 percent of sales. Since the District is subject to the Section 133 cost of service reporting requirements, it has a direct interest in this proceeding.

III.

The Commission's Notice of Inquiry requests comments on the use of, duplicity of and alternatives or revisions to the Section 133 reporting requirements. In brief, the District is unable to discern any meaningful use for the Section 133 reports. Continued reporting simply increases the cost of utility service to customers and is dramatically out of proportion to any conceivable benefits which might obtain by such reporting. In fact, for all the flurry and fanfare accompanying the enactment of Section 133, it is apparent that the section has not lived up to its expectations given the General Accounting Office's frank assessment that "the cost-of-service data requirements are burdensome and costly to utilities, and of little current use to States and intervenors." This is particularly the case with respect to public power entities, such as the District, where public accountability as to rates and service is at its zenith.

A. Use of Reported Information

The data filed by the District pursuant to the Commission's Section 133 regulations has not been used in Nebraska or other regulatory proceedings. Indeed, the continued necessity of the 133 filings is especially questionable in view of the fact that the District's Board itself is the regulatory authority for the District with jurisdiction over rates and charges, and the Board has simply not expressed any need for the required information. The data has not been used in PURPA Section 111 proceedings, Section 210 proceedings or "need for power" proceedings. Further, the District has not found the 133 information useful as to the marginal cost and load data necessary to assess the cost effectiveness of investment and pricing actions since the data is only for one year (1979), and, even at that, it is incomplete for a portion of the District's resources. Moreover, 70 percent of the District's sales are wholesale, and none of the wholesale customers file such reports.

Verification of Section 133 reports by state agencies or this Commission would create a unique triumph of bureaucracy for sake of bureaucracy alone. What other purpose could be served by directing State or federal regulatory resources to verify information which is ultimately unused in any event? Also, if the information is ever used, it is likely to arise in a regulatory proceeding where safeguards are already amply present to assure the veracity of it. In short, independent verification would seem to be unnecessary at best.

As to the District, data collected under Part 290 has little, if any, practical application since the information on resources is incomplete and the District has very substantial wholesale sales. More importantly, however, the District is a public power entity -- a political subdivision of the State of Nebraska. Public accountability for the District's rates and service is accordingly very high. Indeed, the special operating and regulatory circumstances of public power, particularly the District, should cause the Commission to exercise its authority under PURPA Section 133(b) to exempt public power entities as a class or at least to review closely the need for particular public power entities, such as the District, to continue providing Section 133 data.

In reviewing whether the Part 290 reporting requirements are inappropriate for a particular utility or class of utilities, the Commission should put special emphasis on the questions of whether the reports serve any useful and cost beneficial purposes in light of the PURPA goals. For the District, it is submitted that the reports have no useful purpose and have only added unnecessary costs to customers bills. Part 290 is simply a case of over-regulation which should be eliminated. In fact, the District is a political subdivision of the State of Nebraska with a popularly elected Board of Directors. The District operates under statutes which require open public meetings with notice of agenda items being published before-hand and generally functions in a "fishbowl" environment with virtually all records open to the public. When taken together, these characteristics warrant exclusion of the District and all similarly situated public power entities from continued compliance with Part 290.

B. Cost of Compliance

The District did invest in special magnetic tape metering (500 units) for retail customers in order to comply with the Section 133 requirements. This investment would probably have been made without the Section 133 requirement since the District did have a need for more extensive customer class load data. However, as discussed below, continued compliance costs are quite substantial given the value of the product generated.

C. Duplicative Reporting Requirements

The extent of duplication of the District's Section 133 reports with other federal or State requirements is not large because Nebraska does not require such filings. Nonetheless, much of the Section 133 reports consist of new data and, thus, is an additional burden for which coextensive benefits are absent.

The added costs of providing the Section 133 information is not insignificant. Considering personnel and computer time, the cost is estimated to be from $15,000 to $20,000 annually. Moreover, this figure does not include load research activity.

It is difficult to envision how State authorities or interested parties could benefit from requiring utilities to collect duplicative data. As one specific example, State authorities and interested parties would gain little, if any, benefit from the District's section 133 report since the data on resources and loads is limited and aged. In fact, since filing its first report, the District has not had any requests for the report from federal or State authorities or any members of the public at large.

D. Alternatives to the Existing Requirements

As previously mentioned, the District specifically requests that it be exempted, pursuant to PURPA Section 133(b), from filing any more Section 133 reports. Further, the Commission should consider exempting all public power entities as a class.

Lastly, we understand that the American Public Power Association (APPA) will move to stay any further Section 133 filings until the proceedings in this docket are completed. The District strongly supports APPA's motion. We note that the Commission has recently adopted precisely this approach in an analogous setting. "Order Suspending Filing of the Form No. 12, 'Power System Statement,'" FERC Docket No. 82-10-000 (issued March 24, 1982). A similar procedure is warranted here.

IV.

In conclusion, the Section 133 reporting requirements are unnecessary, unused, not cost beneficial and should be discontinued in toto. At the least, the Commission should exempt the District and all other similarly situated public power entities as a class from continued Section 133 compliance.

Finally, all Section 133 filings should be suspended during the pendency of this proceeding.

Respectfully submitted,

NEBRASKA PUBLIC POWER DISTRICT

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Dated: April 12, 1982

AFFIDAVIT

DISTRICT OF COLUMBIA: ss

The undersigned, Karen Hastie Williams, having been duly sworn, deposes and says that she is Counsel for Nebraska Public Power District; that she has executed the within Comments of Nebraska Public Power District in Response to Notice of Inquiry; that she is familiar with said Comments and the contents thereof; and that to the best of her knowledge, information, and belief, the facts set forth herein are true.

Karen Hastie Williams
Karen Hastie Williams

Subscribed and sworn to before me this 12th day of April, 1982.

Johnetta D. Jackson
Notary Public

My Commission Expires November 30, [illegible]

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Bio-Energy Systems, Inc.

TESTIMONY OF

MR. BARRETT STAMBLER AND

MR. SAM ENFIELD

ON BEHALF OF THE SOLAR LOBBY

ON S.1885 AND RELATED ISSUES

SUBMITTED TO THE

SUBCOMMITTEE ON ENERGY REGULATION OF THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES OF THE

UNITED STATES SENATE

May 3, 1982

The Solar Lobby is a national organization, with over 48,000 members, that actively promotes the development of energy efficiency and renewable energy resources as critical elements of a solution to the United States' energy supply situation. We appreciate the opportunity to make our views known on S. 1885 and on the importance of the Public Utility Regulatory Policies Act (PURPA) of 1978.

The Solar Lobby has been involved in the development and implementation of Section 210 of PURPA since its inception. Our organization provided oral and written comments on Federal Energy Regulatory Commission's (FERC) regulations and actively encouraged many Solar Lobby members to participate in the rulemaking. Shortly after the regulations were finalized, we produced a handbook on implementing Section 210 of PURPA, "Promoting Small Power Production." Recently, the State of Mississippi challenged the constitutionality of Title I, II and Section 210 of PURPA in Federal District Court in Mississippi. It is now on appeal by FERC in the U.S. Supreme Court. The Solar Lobby, working with the State of Maryland and several other national groups, filed an amicus curiae brief in support of FERC's appeal. We continue to monitor the progress of the program by maintaining contact with our members and other parties actively involved in small power production.

Clearly, PURPA Section 210 attempted to resolve the major institutional barriers to the production of electricity from cogenerators and small power producers and has successfully generated increased interest in energy production from wind, solar, and hydroelectricity. A good indication of the interest in small power production is the number of licenses and preliminary permit applications for small* hydro facilities filed at FERC since the enactment of PURPA Section 210. The number of preliminary permit applications** increased from 76 in 1979, to 501 in 1980, to 1859 in 1981. 1500 applications are projected for 1982. The number of license applications increased from 33 in 1979 to 100 (in addition to 177 "exemption" applications) in 1980. From all appearances, the number of applications will continue to increase. FERC estimates that in 1983, it will receive 321 license applications and 250 exemption applications. In the wind area, several large projects in California and Hawaii are being discussed and many more are in various stages of planning and development. Even photovoltaics, a young technology, is being stimulated by this program. ARCO Solar announced last week, an agreement with Southern California Edison, whereby the utility will purchase the power produced by a 1 MW photovoltaic installation to be constructed by ARCO Solar in Hesperia, California.

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* Below 30 Megawatts

** A preliminary permit provides exclusive rights to build at a designated site for a period of 18 months to 3 years, depending on the terms established by FERC. A license is necessary to proceed with construction and operation of the facility, except that projects smaller than 5 MW may receive an exemption from some provisions of the licensing requirements.

PURPA was enacted in 1978, in part to encourage alternatives to capital-intensive centralized plants as sources of power production, and also to extend the value of fossil fuels where they can be used to generate electricity as well as provide industrial process heat. Section 210 of Title II of this Act was intended to ease the environment within which cogenerators and small power producers operate.

In the past, utilities have been able to discourage small power production by refusing to interconnect with small power producers or by refusing to pay them a "fair" rate for their excess electricity. Under PURPA, Title II requires electric utilities to purchase power generated by these facilities and to sell electricity to them; and it requires that the power bought and sold by such facilities be compensated for at "just and reasonable rates." FERC published regulations on February 25, 1980 that elaborated further on the rate at which utilities must purchase power. The Commission decided to set the rate for purchased power at a level equivalent to the cost of alternative power available to the purchasing utility. In so doing, the Commission decided to assign the maximum incentive within its statutory powers to encourage the development of these resources.

The cost of alternative power available to the utility is referred to as the "avoided cost" -- the amount the utility would have had to spend to produce the same amount of power. According to the FERC's regulations, state utility commissions are to set rates that meet the Federal guidelines. State reaction to this mandate has been mixed; some have approached it enthusiastically, others with substantial reservations.* The electric utility industry has been skeptical in many cases and some have brought legal action seeking to overturn the Commission's rules.

Any uncertainty that arises over the incentives that are embodied in section 210 of PURPA for small power producers could bring hydro, wind, and solar electric development to a rapid halt. Unfortunately, this could very well be the case. While we certainly appreciate the opportunity to discuss the merits of utilities owning cogeneration facilities and small power facilities, we feel that it is premature to discuss this issue exclusively at this time.

On January 22, 1982, the U.S. Court of Appeals in the District of Columbia issued a decision which has had very serious effects on the private development of cogeneration and renewable energy resources. In the case of American Electric Power (AEP) Service Corporation v. FERC, the Court ruled in favor of AEP and invalidated both the Commission's conclusion to fix the rate for purchase at "full avoided cost" (18CFR292-304(b)(2)&(4)) and the FERC's extension of blanket authority to small power producers to "interconnect" with electric utilities without meeting the requirements of Section 210 and 212 of the Federal Power Act (18CFR292.303(c)(1)). In so doing, the Court's decision has cast a cloud over the ongoing development of diversified energy resources. Questions concerning the validity of State programs and financing abound. For example, one financier of small power production projects with an investment banking firm in New York acknowledged that the decision makes it too risky to commit funds to PURPA projects until these issues are resolved. Because of the impact of this ruling on the PURPA program, we strongly believe it is essential to discuss the questions raised by this recent court decision, as well as the issues embodied in S.1885.

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* Attached is an update on state implementation of Section 210 PURPA that appeared in the publication, Energy User News.

It is clear that, as FERC stated in its rulemaking, interconnection provisions of the Federal Power Act would impose undue burdens upon qualifying facilities. Although the Appeals Court sympathized with the Commission's argument, they ruled that exempting small power producers from these sections of the Federal Power Act was not the intent of Congress. However, the Court's decision stated "The Commission need not impose substantial administrative burdens...but rather can adopt streamlined procedures. If...even streamlined procedures are too burdensome, the necessary amendment must come from Congress." It is our opinion, and it seems to be the opinion of FERC's general counsel that FERC cannot implement the statutory mandate to stimulate small power production and cogeneration through administrative means alone. Rather, authority to require interconnection must be provided in statutory authority by the Congress.

With regard to avoided costs, the Court asked FERC to reconsider its rulemaking in this area, stating that "it needs to make its reasoning and finding explicit." The decision questioned FERC's requirement that the power purchase rate be set at 100 percent of avoided costs as opposed to some rate that would split the benefits between the power producers and the ratepayers. The Solar Lobby supports the FERC's interpretation that full avoided costs represent the fair value to utilities of the power generated by small power producers. Furthermore, in our conversations with hydro and wind developers, it has become clear that a power purchase rate set at full avoided costs is an essential bargaining factor in their contract negotiations with electric utilities. It is important to note that, in many instances, contracts arrived at between small power producers and utilities involve power purchases rates that are less than the full avoided cost.

We see little likelihood that the questions of avoided costs will be resolved in further judicial or administrative proceedings for a very long time. If FERC, for example, is required to reopen their rulemaking, it is very likely this process could take over a year. Moreover, any Supreme Court ruling on this issue would take more than a year's time, assuming that the Court even accepts the case. We have surveyed small power producers and this time delay could very well drive most companies out of business.

Thus, in order to resolve the AEP case and to maintain the consistency in the PURPA program that is essential to small power producers as well as utilities, the Solar Lobby urges that the Congress address this situation. We recommend legislation that would uphold the principle of access to the utility grid by small power producers through mandatory interconnection and that would require electric utilities to purchase power from qualifying facilities (QF's) at an amount equal to their avoided costs of power.

The Solar Lobby does recognize the value of a rate-setting mechanism that more closely involves the states' proper function in overseeing the relationships between electric utilities, their ratepayers and small power producers. There will be instances where factors in a given utility service area or state dictate a power purchase rate that differs from full avoided costs.* In the case of regulated electric utilities, the state regulatory body should have authority to depart from full avoided costs if a lower power purchase rate would be consistent with the interests of electric utility ratepayers and would be sufficient to encourage development of small power production and cogeneration. If the state regulatory authority does not take action, or until it does take action, full avoided costs should stand as the power purchase rate.

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* The diesel cogeneration problem in New York City may represent such a case.

In the case of those qualifying facilities that entered into contract with an electric utility prior to the enactment of this law, we feel that existing power purchase contracts should remain in effect. Considerable time and effort has gone into the negotiation of these contracts and we feel that they should be honored by those who entered into them in good faith.

Nonregulated electric utilities should be required to purchase power from qualifying facilities at full avoided costs, unless and until they determine that a lesser or greater rate is consistent with the interest of the ratepayers and sufficient to encourage the development of small power production and cogeneration. If they so determine, they should be required to publish their reasoning for departing from the full avoided cost.

The Solar Lobby is concerned about the thousands of individuals and businesses that may want to apply the incentives provided by PURPA and develop renewable resources for electricity generation themselves. Currently, several of our members own small wind machines or are located next to developable streams and through these small facilities can satisfy their own energy needs. Furthermore, they do now or will in the future generate excess power that can be sold to their local utility. However, it is not practical for these very small power producers to enter into complex negotiations with electric utilities over contracts for interconnection and sales to the utility of this excess power. In formulating the existing PURPA regulations, the Federal Energy Regulatory Commission addressed this situation by requiring state regulatory authorities and non-regulated utilities to publish standard rates for the purchase of power from qualifying facilities of 100 kw or less. The Commission justified this approach, stating; "If the Commission were to require individualized rates,..., the transaction costs associated with the administration of the program would likely render the program uneconomic for this size of qualifying facility." (Federal Reg. Feb. 25, 1980, p. 12223 Sec. 292.304 (c)).

Unfortunately, the Court's decision on avoided costs leaves the future of standarized tariffs for QFs of 100 kw or less unresolved. It is crucial for the future development of residential and business applications of small power production technologies that this provision be included in any legislative solution. In fact, the Solar Lobby recommends that this provision of the law should require the electric utility to develop or maintain existing standard contracts for power purchases from qualifying facilities of 100 kw or less at avoided costs. Should a rate less than full avoided cost be established for such purchases (with State regulatory approval in the case of regulated utilities or by publication in the case of non-regulated utilities) the lesser rate must also be expressed as a standard one.

Again, we must re-emphasize the point that if the AEP v. FERC case is not resolved, a discussion of utility ownership of small power production facilities is premature. Without required interconnection and an established purchase rate by the FERC or state, electricity generation from co-generators and small producers will not proceed.

The importance of resolving this Court case was vividly brought to our attention during recent discussions with one hydro developer involved in a contract negotiation with an electric utility over the purchase of power from a prospective hydro site. Negotiations had proceeded to the point that a contract was drawn up and ready for final signature. However, upon being informed of the status of the AEP case, the utility abruptly broke off negotiations, and the project has not gone forward.

Utility Ownership

S. 1885 presents a series of problems for small power producers and cogenerators. The Solar Lobby has spent a large amount of time talking to different renewable energy developers. It is important to note that many small power producers have concerns and real experiences with utility intransigence but are afraid to publicly name utilities or specific instances. These producers know that they have to continue to work with these utilities no matter what Congress decides. Thus, we hope to be of service to the Subcommittee, by relating examples of difficulties that have occurred between utilities and small power producers. At this point, we would like to lay out the various reasons why lifting utility ownership restrictions as specified by S. 1885 may result in less cogeneration and renewable energy being developed.

The purpose of PURPA section 210, as discussed earlier, is to encourage the development of renewable energy resources and cogeneration opportunities. It has, for example, successfully stimulated interest in the revitalization of existing but dilapidated dams and in the construction of new hydroelectric facilities that are cost-effective. This interest has been reflected in the increased liscensing activity at the FERC that we described earlier.

We strongly hold the view that eliminating the restrictions on the participation of utility-owned subsidiaries in the PURPA program would seriously undermine the original intent of PURPA. Had utilities been aggressively developing cogeneration and renewable resources, there would not have been the need for PURPA in the first place. However utilities were not proceeding in this direction, and Congress felt that it was necessary to provide incentives to third party developers. Essentially, Congress wanted to unleash the entrepeneurial initiative of small businesses in the effort to resolve our energy problems.

It appears that most utilities continue to be uninterested in the smaller-scale applications addressed by PURPA that we believe can contribute significantly to the nation's future energy supply mix. Development of these applications would better meet, over time, the more gradual growth in demand for electricity. And in today's tight capital market, financing for smaller, decentralized facilities should be more easily available to financially-strapped utilities.

However, we have not found strong evidence supporting the utilities' contention that they are sincerely interested in developing cogeneration and renewable energy resources. It is unclear why electric utilities cannot undertake renewable energy projects under the current rate structure. With or without PURPA, a utility should be investing in the least cost energy source. A utility able to reduce costs to its ratepayers by investing in cogeneration or small power production should be doing so and be compensated in its rate base.

We do not see this occuring. In fact, we have evidence that some utilities are blocking the progress of small power producers at certain sites, but not pursuing development of those same sites themselves. This is being accomplished, for the most part, through the denial of financing for the small power developer. Some utilities are using their close relationships with banks to prejudice those banks against the small power development proposal. Yet even in instances where the utilities have shown interest in developing the site in question themselves, the utilities have failed to proceed once financing for the small developer had been rejected. It is cases like these that lead us to question the interest of utilities in developing smaller scale renewable resources, even on their own terms.

Moreover, with utilities pursuing objectives such as the rate basing of Construction Work in Progress (CWIP), the repeal of the Public Utilities Holding Company Act (PUHCA), and even a $50 billion financial relief package, we question whether it is realistic to expect utilities to be seriously interested in developing decentralized sources of energy.

In this same regard, if PURPA projects are so attractive, why have electric utilities not taken better advantage of the opportunity to invest in projects up to the 50 percent limitation? The financial return should certainly be attractive. And independent developers have shown an ability to complete licensing procedures and manage projects in an efficient and effective manner. Certainly some utilities, like Niagara Mohawk, Florida Light and Power, Southern California Edison, and Pacific Gas and Electric, have made investments in qualifying facilities. We commend these utilities and encourage future investment. However, quite frankly, much of this limited activity only occured because of strong pressure from the State Public Utility Commissions (this is definitely the case for SCE and PGE in California). In general we simply have not seen widespread utility interest in small power production.

It is problems with financing, for example, that address the concern expressed by some people that restrictions on utility ownership should be lifted because electric utilities should be treated equally with small power producers. The problem is that utilities and qualifying facilities are inherently unequal. One is a regulated monopoly with extensive financial and political clout, while the other is a small business with very little muscle. In many cases, the 50 percent ownership restriction gives the small power producer leverage and some form of parity with the electric utility. One developer gave us a specific example. On several medium-sized hydroelectric facilities (10-30 MW), the developer will file a license application with FERC and the electric utility in that same area will file an application on top of the developer's license application. FERC, like any bureaucratic organization, will tend to process the less controversial applications first. Since the utility has political clout, controversy surrounds a hydro-site where the utility and the developer file an application on the same site. Under the present situation, the utility knows it cannot own the entire site and receive PURPA benefits. Thus, the developer can trade up to 50 percent of the project to a utility in exchange for assistance from the utility and withdrawal of the utility's license application. If the ownership restriction is lifted, this bargaining leverage is taken away. This particular developer believes the utility will then refuse to negotiate with the small developer and wait it out while the license remains idle at FERC.

There are a number of other problems with utility ownership. First, as FERC Chairman Butler recognized at the Subcommittee hearing, PURPA could distort utility investment decisions at the ratepayers' expense. A utility could continue to undertake the marginal projects itself, leaving those in the rate base and inflating avoided costs, while letting its unregulated subsidiary undertake the most lucrative projects. Second, given the variation in cost from project to project, there are serious risks of self-dealing. This has been a problem with utility purchases of coal from subsidiaries, even though the market price of coal is much more easily determined than in the case of power purchases from hydro, wind, biomass, and other renewable energy sources. In hearings held in the House Energy Committee last year, the American Public Power Association testified that,

> "It is not in the public interest to allow the companies or their subsidiaries to become owners of QFs, sell power to themselves at 'avoided cost,' and pass these costs on to their consumers without the Federal or the state regulatory commissions exerting any real control as to whether or not these were appropriate investments. This is analogous to the "captive mines" situation that prevailed in parts of the electric utility industry. Ownership by some utilities of captive mines gave them opportunities to show a so-called 'regulated' rate of return by the utility itself, but conceal profits on their mining operations. The FERC has had many problems in trying to control these hidden fuel costs. The same potential probelm is associated with allowing utility subsidiaries to sell services, including energy, to parent utilities in an unregulated fashion."

Another problem arises from the opportunities utilities have to discriminate against private developers by manipulating the ordering of contracts. Avoided cost is not a fixed rate but should decline over time. Initially, PURPA projects will replace the more expensive, oil-fired peaking plants. However, PURPA projects that come on line later will replace less expensive electric generating facilities, and thus, the avoided cost rate will decline. Under this scenario, a utility could sign first with its subsidiary to claim the highest avoided cost rate, leaving private developers with the lower rates.

Our organization has seriously contemplated the possibility of legislating safeguards that would protect cogenerators and small power producers while allowing increased utility participation; however, we do not feel that any such safeguards are feasible. For example, reliance on current anti-trust law is completely inadequate and unenforcable. Even though the penalty for an anti-trust violation is triple damages, anti-trust remedies are only available after the fact, usually many years after the damage has been done. Furthermore, most small businesses involved in the development of renewable energy and cogeneration cannot afford to pursue litigation. The financial resources of an electric utility dwarf that of a small power producer. Anti-trust cases can drag on for years without a definite outcome due to the skill of the defendant's lawyers. Although large cogenerators may have the political and financial clout to withstand the strength of the electric utilities, small, power producers most definitely do not.

Another important consideration in this issue is the practicality of relying more heavily on state regulatory bodies for oversight of this expanded area of utility activity.

We respect the opinion of the National Association of Regulated Utility Commissioners (NARUC) on this question. They clearly stated in their testimony before the Subcommittee that:

> ".., by allowing electric utilities to engage in unregulated business ventures within the power business, the legislation would immensely complicate the task of State regulators, whose responsibility it would be to ensure that utility-subsidiary transactions are at arms-length and not detrimental to the utility's monopoly ratepayers."

Despite our general skepticism about the ability to write adequate safeguards against utility abuses in this legislation, it might be feasible to allow full utility ownership under PURPA in certain circumstances. For example, a cogenerating system produces both thermal and electric energy. In order to qualify under PURPA, the regulations require that the thermal energy used must represent at least 5 percent of the total energy produced. An electric utility often does not have any use for this 5 percent thermal energy. Thus, an industrial process must be co-located with the generating facility. This industry is an essential part of the overall system, and thus has leverage to use in protection of its status vis a vis the utility. In addition, the industrial facility is probably already an important customer of the electric utility and will very likely have a good working relationship established with it. Therefore, it might make sense to allow utility ownership for cogenerating facilities, but not for small power production facilities.

In conclusion, we feel that it is premature to deal with utility ownership unless one resolves the larger problems of interconnection and power purchase rates raised by the AEP v. FERC litigation. While we look forward to the time when utilities embrace small power production enthusiastically, we are seriously concerned that extending to utilities the benefits of full ownership under PURPA at this time would definitely not result in more development of renewable resources for the generation of electricity. We are also seriously concerned that full utility ownership under PURPA will not result in more development of smaller scale renewable resources for electricity generation. The Solar Lobby strongly believes that the conditions that Congress addressed when it enacted PURPA in the first place are still in effect, and that to retreat from that position would seriously impair the development of these technologies and resources so badly needed by this country. Therefore, we would find it hard to support S.1885 if it eliminates existing restrictions on utility ownership.

Again, we appreciate the opportunity extended by the Subcommittee to address this area of federal policy and would be happy to provide further assistance if it is needed.

STATES' COGENERATION RATE-SETTING UNDER PURPA

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to have in place by March 20, 1981, mechanisms to assure that cogenerators receive just, reasonable and non-discriminatory prices for sales of electricity to utilities. As an incentive to cogenerate, the rates were to be based on the utility's "full avoided costs," not on the utility's average cost of service. This time last year, Energy User News found that 27 states had missed the deadline. As of last week, 14 states still did not have final rules in place. Two recent court cases have challenged PURPA's constitutionality and the full avoided cost ruling, throwing utilities' rate-setting into confusion. (See box, page 17.) The status of state cogeneration proceedings under PURPA and the approved rates for the sale of cogenerated power to utilities (in cents per kilowatt hour) are shown below.

STATE	STATUS	RATES	CONTACT
Alabama Public Service Commission	Revised rates as of May 1981 for production of 100 kw or less. Rates for larger producers still pending as they were a year ago until industrial users agree to terms with utilities.	For producers of 100 kw or less: Option A (standard rate) is 2.17 cents/kwh June through October, and 2.05 cents/kwh November through May. Option B (time of day rate) is 2.50 cents/kwh for on-peak and 2.17 cents/kwh for off-peak June through October, and 2.14 cents/kwh for on-peak and 2.05 cents/kwh for off-peak November through May.	Wallace Tidmore, PSC, (205) 832-3421.
Alaska Public Utilities Commission	PUC has begun hearings. Decision expected in a few months.	Unavailable.	Mary Fitzgerald-Jones, PUC, (907) 276-6222.
Arizona Corporation Commission	Final order. Utilities must file purchased power rates with ACC for producers of 100 kw or less; rates to be basis for negotiating rates for large industrial cogenerators and to be based on avoided cost.	Tucson Electric Power Co.: For producers of 100 kw or less, nonfirm, summer, 4.4 cents/kwh; winter, 3.5 cents/kwh; firm, summer, 4.84 cents/kwh; winter, 3.85 cents/kwh.	Jim Apperson, ACC, (602)-255-4251.
Arkansas Public Service Commission	Pending. Draft rule expected late March, generic hearing in late summer.	One proposal in draft rule will set standard rate for all producers of up to 1,000 kw.	Dana Nixon, PSC, (501)371-1792.
California Public Utilities Commission	Utilities protest PUC's Jan. 21 order specifying full avoided cost and other standards, including forbidding utilities to buy less power under certain conditions, assigning higher value than utilities want to nonfirm power, and requiring utilities to file reports on wheeling of cogenerated power. Utilities have filed sample rates but say rate lower than full avoided cost can benefit other customers without discouraging cogeneration. PUC may decide April 4 whether to rehear issues raised by utilities.	Pacific Gas & Electric Co.: For small power producers (current rate updated every 3 months), 7.750 cents/kwh, on-peak; 7.334 cents/kwh, partial peak; 6.548 cents/kwh, off-peak. Capacity payments vary depending on firmness of power and length of contract period.	John Quinley, PUC, (415) 557-1150.

Colorado Public Utilities Commission.	Rates still in negotiation. Decision expected by Jan. 1, 1983.	Unavailable.	Michael Homyaki, PUC, (303) 866-4300.
Connecticut Department of Public Utility Control	Final off-peak and on-peak rates were established in November 1981 for firm and non-firm users for the state's three major electric utilities.	**Connecticut Light and Power and Hartford Electric Light Co.**: (March filing) non-firm peak, 5.5 cents/kwh; non-firm off-peak, 4.30 cents/kwh; firm peak, 5.65 cents/kwh; firm off-peak, 4.44 cents/kwh. **United Illuminating**: (March filing) non-firm peak, 5.24 cents/kwh; non-firm off-peak, 4.56 cents/kwh; firm, on peak, 5.62 cents/kwh; firm off-peak, 4.96 cents/kwh.	DPUC Research Div., (203) 827-1553.
Delaware Public Service Commission	Final PSC order effective March 1.	**Delmarva Power and Light Co.**: For units of 100 kw or less, summer on-peak, 6.37 cents/kwh; off-peak 3.16 cents/kwh; winter on-peak, 6.25 cents/kwh; off-peak, 3.73 cents/kwh. For larger units, rates are negotiable.	Leon Ryan, PSC, (302) 736-3233.
Florida Public Service Commission	Temporary rates currently reflect estimated fuel costs of utilities. PSC will vote at end of March on staff recommendation to revise rates to reflect actual fuel costs of utility companies and to require them to make public their tariffs of estimated avoided fuel costs for 2-year period.	**Florida Power and Light Co.**: Less than 100 kw, on-peak is 5.28 cents/kwh and off-peak, 4.681 cents/kwh; more than 100 kw, on-peak is 5.081 cents/kwh and off-peak, 4.505 cents/kwh. **Gulf Power Co.**: Under 100 kw, on-peak is 2.629 cents/kwh and off-peak, 2.213 cents/kwh; over 100 kw, on-peak is 2.052 cents/kwh and off-peak, 2.106 cents/kwh. **Tampa Electric Co. (TECO)**: Under 100 kw, on-peak is 6.813 cents/kwh and off-peak, 4.378 cents/kwh; over 100 kw, on-peak is 6.446 cents/kwh and off-peak, 4.142 cents/kwh. **Florida Power Corporation**: Not available.	Bonnie Davis, PSC, (904) 487-2740.
eorgia ublic Service Com-ission	Proceedings suspended. PSC still awaiting outcome of Supreme Court decision on constitutionality of PURPA.	Not available.	Sam Weaver, PSC, (404) 656-4141.
awaii ublic Service Com-isson	In effect.	Utilities are required to pay 100% avoided costs but one cogenerator in state is receiving less because "contract was signed before PURPA was passed," according to PUC.	Leroy Yuen, PUC, (808) 548-3990.
aho ublic Utilities Com-ission	1981 rates in effect. Hearings to revise 1982 rates begun.	**Idaho Power Co.**: Non-firm, 1.42-3.86 cents/kwh; firm, 5.93 cents/kwh. **Washington Water Power Co.**: Non-firm, 2.7 cents/kwh; firm, 5.37 cents/kwh. **Utah Power and Light Co.**: Non-firm, 2.2 cents/kwh and firm, 4.79 cents/kwh. **Pacific Power and Light Co.**: Non-firm on-peak, 2 cents/kwh; off-peak, 1.3 cents/kwh; firm, 6 cents/kwh. (Pacific Power rates are only ones revised and approved for 1982 by PUC.)	William Drummond, PUC, (208) 334-3456.

STATES' COGENERATION RATE-SETTING UNDER PURPA

STATE	STATUS	RATES	CONTACT
Illinois Commerce Com-	Rates approved per utility.	**Commonwealth Edison**: For cogenerators producing under 1,000 kw during summer on-peak, 5.31 cents/kwh; off-peak, 2.90 cents/kwh; winter on-peak, 5.17 cents/kwh; off-peak, 3.37 cents/kwh. For cogenerators producing over 1,000 kw during summer on-peak, 5.23 cents/kwh; off-peak, 2.86 cents/kwh; winter on-peak, 5.09 cents/kwh; off-peak, 3.32 cents/kwh. **Illinois Power Co.**: Summer on-peak, 2.42 cents/kwh; off-peak, 1.55 cents/kwh; winter on-peak, 5.17 cents/kwh; off-peak, 3.37 cents/kwh. **Central Illinois Light Co.**: average on-peak, 2.4 cents/kwh; average off-peak, 2.2 cents/kwh. **Interstate Power Co.**: Summer on-peak, 2.45 cents/kwh; off-peak, 2.05 cents/kwh; winter on-peak, 2.19 cents/kwh; off-peak, 2.05 cents/kwh. **Central Illinois Public Service Co.**: Summer on-peak, 1.97 cents/kwh; off-peak, 1.63 cents/kwh; winter on-peak, 1.88 cents/kwh; off-peak, 1.66 cents/kwh. **Union Electric Co.**: Summer, 1.77 cents/kwh; summer time-of-day average, 1.75 cents/kwh; winter, 1.52 cents/kwh; winter time-of-day average, 1.60 cents/kwh. **South Beloit Water, Gas and Electric Co.**: On-peak, 2.30 cents/kwh; off-peak, 1.70 cents/kwh.	Joseph Gillan, ICC, (217) 785-0326.
Indiana Public Service Commission	Rates in effect.	**Indiana & Michigan Electric Co.**: time of day on-peak, 1.36 cents/kwh; off-peak, 0.81 cents/kwh; non-time of day rates 0.81 cents/kwh. **Indianapolis Power & Light Co.**: rates for purchase of 72,000 kwh or less per month during winter weekday hours, 1.34 cents/kwh; other hours 1.09 cents/kwh; summer weekday rates, 1.42 cents/kwh; other hours, 1.13 cents/ kwh; purchase of over 72,000 kwh/month, 1.21 cents/kwh. **Northern Indiana Public Service Co.**: summer on-peak, 2.83 cents/kwh; off-peak, 2.46 cents/kwh; winter on-peak, 3.33 cents/kwh; off-peak, 2.75 cents/kwh. **Public Service Co. of Indiana**: 1.33 cents/kwh. **Richmond Power & Light Co.** 0.914 cents/kwh. **Southern Indiana Gas & Electric Co.** for first 72,000 kwh/month during summer on-peak, 1.49 cents/kwh; summer off-peak, 1.02 cents/kwh; winter on-peak, 1.15 cents/kwh; off-peak, 1.0 cent/kwh; rates for over 72,000 kwh/month during summer on-peak, 1.36 cents/kwh; off-peak, 1.03 cents/kwh; winter on-peak, 1.10 cents/kwh, off-peak, .99 cents kwh.	William D. Boyd, PSC, (317) 232-2711.
Iowa State Commerce Commission	Rates approved for only one of 9 utilities. Other rates expected to be approved by year's end.	**Iowa Public Service Co.**: Energy, 1.82 cents/kwh; time-of-day on-peak, 2.03 cents/kwh; off-peak, 1.64 cents/kwh.	Robert Latham, ISSC, (515) 281-5701.
Kansas Corporation Commission	Pending. Order, expected in 2 months, will probably not contain specific rates. Several utilities have filed sample rates.	**Kansas Power & Light Co.**: In effect since 1979, applies to producers of less than 50 kw, about 2 cents/kwh. Case by case negotiation with larger cogenerators.	Eva Powers, KCC, (913) 296-5468.

Iowa State Commerce Commission	Rates approved for only one of 9 utilities. Other rates expected to be approved by year's end.	**Iowa Public Service Co.**: Energy, 1.82 cents/kwh; time-of-day on-peak, 2.03 cents/kwh; off-peak, 1.64 cents/kwh.	Robert Latham, ISSC, (515) 281-5701.
Kansas Corporation Commission	Pending. Order, expected in 2 months, will probably not contain specific rates. Several utilities have filed sample rates.	**Kansas Power & Light Co.**: In effect since 1979, applies to producers of less than 50 kw, about 2 cents/kwh. Case by case negotiation with larger cogenerators.	Eva Powers, KCC, (913) 296-5468.
Kentucky Utility Regulatory Commission	Plan completed in January. Legislative Research Commission approval expected in April.	Not set until plan is approved.	Richard Heman, KURC, (502) 564-3940.
Louisiana Public Service Commission	Pending.	Not available.	Arnold Chauviere, PSC, (504) 342-1403.
Maine Public Utilities Commission	Temporary rates established for state's three major electric utilities. PUC still holding hearings to establish final rates expected to be established by summer.	**Central Maines Power Co.**: (January filing) 5.5 cents/kwh. **Banghor Hydroelectric Co.**: (August filing) 5 cents/kwh. Temporary rates, based on utilities' full avoided cost of power, also established for **Public Service Co.** of N.H. but were unavailable at press time.	Maine PUC, (207) 289-3831.
Massachusetts Department of Public Utilities	Final rates established in July (Order no. 535).	**Boston Edison Co.** (highest buyback rates in state): If transmission line is over 115 kilovolts (kv), peak rate is 7.64 cents/kwh; off-peak rate, 4.724 cents/kwh, and flat (for electricity supplied 24 hours a day), 5.99 cents/kwh. For transmission lines between 14 and 115 kv, peak is 7.702 cents/kwh; off-peak, 4.746 cents/kwh, and flat, 6.033 cents/kwh. For transmission lines having less than 4 kv, peak is 8 cents/kwh; off-peak, 4.967 cents/kwh, and flat, 6.350 cents/kwh. **Massachusetts Electric Co.** (lowest buyback rates in state): For 150 kv and above, peak is 4.9 cents/kwh; off-peak, 3.85 cents/kwh, and flat, 4.35 cents/kwh. Between 14 kv and 150 kv, peak is 4.9 cents/kwh; off-peak, 3.88 cents/kwh, and flat, 4.41 cents/kwh. Between 4 and 14 kv. peak is 5.19 cents/kwh; off-peak, 3.97 cents/kwh, and flat (or average), 4.54 cents/kwh. Below 4 kv, peak is 5.23 cents/kwh; off-peak, 3.98 cents/kwh, and flat, 4.57 cents/kwh. All other utilities' buyback rates fall between those specified for Boston Ed and those listed for Massachusetts Electric Co.	Fuel Charge Div., DPU, (617) 727-9748.
Maryland Public Service Commission	Pending. Proposal under consideration by PSC.	Plan would incorporate federal regulations into Maryland state law. Rates not available.	Paul Daniel, PSC, (301) 659-6021.
Michigan Public Service Commission	Rates in effect.	Average energy rate for 9 utilities, 3-4 cents/kwh; average time-of-day rates 2-5 cents/kwh.	Donald Johns, PSC, (517) 373-8171.
Minnesota Public Service Commission	PSC working on proposed regulations. Hearings scheduled April 30 to May 11.	Unavailable.	Stuart Mitchell, PSC, (612) 296-8662.

TATES' COGENERATION RATE-SETTING UNDER PURPA

TATE	STATUS	RATES	CONTACT
ppi Service Com-	Awaiting appeal of Mississippi's challenge to constitutionality of portions of PURPA. Most development work for setting cogeneration buyback rates has already been done.	Not available.	Keith Howle, PSC, (601)354-7565.
Service Com-	Final order. Utilities must file purchased power rates for producers of 100 kw or less of nonfirm power. Firm producers of 100 kw or less should negotiate with their utilities; PSC will arbitrate if necessary. Larger power producers should negotiate. One utility's rate has been approved so far.	Kansas City Power & Light (approved): 1.63 cents/kwh is average rate for nonfirm producers of 100 kw or less.	
ervice Com-	Final rates established for two different utilities; rates for third utility expected to be approved in 2 weeks.	Montana Power Co.: short-term energy, 2.34 cents/kwh; long-term energy (requires at least four year contractual commitment), 4.09 cents/kwh; peak electricity, 6.74 cents/kwh. Montana Dakota Utilities: short-term energy, 2.16 cents/kwh; long-term energy, 5.58 cents/kwh; peak electricity, 5.52 cents/kwh. Rates for Pacific Power and Light Co. pending.	Ted Otis, PSC, (406) 449-2649.
Service Com-	Final rules adapted August 1981.	Not yet established because no industrial cogenerators or small power producer have expressed interest in hooking into utility grid system.	PSC, (702) 885-3409.
ampshire Utility Com-	Final rates established for small power producers, tentative rates set for cogenerators. Since no utility has yet filed request to use cogenerated electricity rate, it may be challenged by utilities or cogenerators.	For small power producers of non-reliable power sources, 7.7 cents per kwh; for reliable sources, 8.2 cents. Tentative rate for cogenerated electricity is 7 cents per kwh.	Sarah Voll, PUC, (603) 271-2437.
rsey of Public	Final tariffs approved by board Oct. 11. Tariffs for Atlantic City Electric Co. and Public Service Electric and Gas Co. effective Dec.30. Rates for Jersey Central Power and Light Co. effective Feb. 11.	Public Service Electric and Gas: 8.08 cents/kwh, on-peak; 5.87 cents/kwh, intermediate; 4.37 cents/kwh, off-peak. Jersey Central: 6.73 cents/kwh, on-peak; 4.46 cents/kwh, off-peak. Atlantic City Electric: 5.36 cents/kwh.	Steve Gable, BPU, (201) 648-3440.
exico Service Com-	Final order. Utilities must file buyback rates for cogenerators of less than 100 kw, based on avoided cost. Buyback rates for larger cogenerators are to be negotiates case by case, but based on avoided cost as determined for small producers' contracts.	Public Service Co. of New Mexico set rate for cogenerators of 100 kw or less, either firm or nonfirm, June-August; power bought at 12.6 kv, 3.472 cents/kwh; bought at lower voltage, 3.664 cents/kwh. Other months: power bought at 12.6 kv, 3.826 cents/kwh; bought at lower voltage, 4.013 cents/kwh.	Tom Halpin, PSC, (505)827-3361.
ork Service Com-	Temporary rates in effect. PSC delayed final decision due to Washington, D.C., federal court of appeal decision calling FERC order into question.	For small power producers, (those who generate power with a source other than oil), rate is 6 cents per kwh which will remain in effect until avoided cost rates are established by PSC.	Craig Indyke, PSC, (518) 474-6515.

Carolina Utilities Com-	In effect since September 1981.	**Carolina Power and Light Co.**: Energy credit, on-peak hours (10 a.m. to 10 p.m. Monday to Friday, May to Oct.; 6 a.m. to 1 p.m. and 4 p.m. to 9 p.m., Monday to Friday, November to April), variable annual rate is 2.8 cents/kwh, and the fixed long term rate is 3.00 cents/kwh for 5 years, 4.4 cents/kwh for 10 years, and 5.56 cents/kwh for 15 years. For off-peak hours, variable annual rate is 2.07 cents/kwh, and fixed long term rate is 2.83 cents/kwh for 5 years, 3.31 cents/kwh for 10 years, and 4.04 cents/kwh for 15 years. Capacity credit for July-October is 1.40 cents/kw for variable annual rate and 5 and 10 year long term fixed rates, and 2.39 cents for 15 years. Remaining months' rate is 1.29 cents/kw for variable annual rate and 5 and 10 year long term rates, and 2.08 cents/kw for 15 years. **Duke Power Co.**: Energy credit, on-peak hours (7 a.m. to 11 p.m. Monday to Friday), variable annual rate is 2.12 cents/kwh, and fixed long term rate is 2.87 cents/kwh for 5 years, 3.83 cents/kwh for 10 years, and 5.02 cents/kwh for 15 years. For off-peak hours, variable annual rate is 1.6 cents/kwh, and fixed long term rate is 2.15 cents/kwh for 5 years, 2.96 cents/kwh for 10 years and 3.78 cents/kw for 15 years. Capacity credit for July-October and January-April is 1.11 cents/kw for variable annual rate and 5 and 1 year fixed long term rates, and 1.17 cents/kw for 15 years. Remaining months' rate is .66 cents/kw for variable annual rate and the fixed long term rates for 5 and 10 years, and .69 cents/kw for 15 years. **Virginia Electric and Power Co. (VEPCO)**: Energy credit rate for on-peak hours (8 a.m. to 11 p.m., Monday to Friday) is 5.023 cents/kwh, and for off-peak, 3.132 cents/kwh. Capacity credit for systems operating up to 5 years is .803 cents/kwh, and for those over 5 years, 1.253 cents/kwh. **Natahala Power and Light Co.**: Energy credit for all cogenerators is 2.441 cents/kwh and the capacity credit is 2.997 cents/kw.	Tim Carrere, PUC, (919) 733-2267.
Dakota Service Com-	Rates in effect.	Average rates for non-firm power, 1.91 cents/kwh; average time-of day, on-peak, 2.21 cents/kwh; off-peak 1.57 cents/kwh. Average firm energy rates, between 1.97 and 3.08 cents/kwh.	Steven Kahl, PSC, (701) 224-4078.
Jtilities Com-	Recommended tariffs not yet submitted to commission. Review expected in 30 days.	Not available.	Alan Pound, PUC, (614) 466-7750.
na ation Com-	Final order. Utilities' cogeneration rates set for three types of small producers (under 100 kw): photovoltaic, wind and stored hydro. Rates are considered experimental until fall 1983.	Approved buyback rates for small producers range from 0.7 cents per kwh to 4 cents per kwh depending on utility's avoided cost, firmness of supply, season and time of availability. Larger producers and utilities will negotiate rates.	Jim Winters, OCC, 405-521-2335.
Utility Com-	Hearings held. Final commission order on tariffs pending.	Proposed tariffs for those producing 100 kw or less, .720 cents/kw of capacity; 4.339 cents for contracted energy; 2.242 cents for non-contract supply.	Leon Hagen, PUC, (503) 378-7998.
vania Jtility Com-	Pending. PUC scheduled within 30 days.	Formulas for estimating avoided costs developed by staff and expected to be included in final commission order.	Tom Clift, PUC, (717) 783-1373.

STATES' COGENERATION RATE-SETTING UNDER PURPA

STATE	STATUS	RATES	STATUS
Rhode Island Public Utility Commission	Final rates established March 20, 1981.	**Narragansett Electric Co.** last filed buyback rates with PUC in February. At that time, on-peak electricity was 5.57 cents/kwh, off-peak electricity was 4.4 cents/kwh, and electricity supplied on a 24-hour basis (flat) was 4.9 cents/kwh. **Blackstone Valley Electric Co.** last filed buyback rates in November; 6.67 cents/kwh, on-peak; 5.08 cents/kwh, off-peak, and 5.76 cents/kwh for electricity supplied on a 24-hour basis. **Newport Electric Co.** last filed buyback rates with PUC in January. On-peak was 6.66 cents/kwh; off-peak, 5.64 cents/kwh, and flat, 6.28 cents/kwh. **Pascoag Fire District** has no cogenerators or small power producers, and therefore has filed no rates. **Block Island Power Co.** negotiates contracts on case-by-case basis.	Laura Dowd, PUC, (401) 277-3500.
South Carolina Public Service Commission	In effect.	**Duke Power Co.:** Energy credit rate for on-peak hours (7 a.m. to 11 p.m., Monday to Friday) is 1.98 cents/kwh; off-peak, 1.49 cents/kwh. Capacity credit is $5 per month per kw. **South Carolina Electric and Gas Co.:** Energy credit for on-peak hours (9 a.m. to 11 p.m., Monday to Friday, May to November; 7 a.m. to 10 p.m., Monday to Friday, December to April) is 3.286 cents/kwh; off-peak, 2.275 cents/kwh. Capacity credit is $2.75 per month/kw. **Carolina Power and Light Co.:** Energy credit for on-peak hours (10 a.m. to 10p.m., Monday to Friday, May-October; 6 a.m. to 1 p.m. and 4 p.m. to 9 p.m., Monday to Friday, November to April) is 2.8 cents/kwh; off-peak, 2.07 cents/kwh. Capacity credit for July to October is $3.80 per month per kw. and for remaining months, $3.35 per month per kw.	Randy Watts, PSC, (803) 758-5362.
South Dakota Public Utilities Commission	PUC decision pending on proposed rates.	Unavailable.	Walter Washington, PUC, (605) 773-3201.
Tennessee Tennessee Valley Authority Board of Directors	In effect. Revised rates as of October 1981.	For less than 100 kw systems or those with no time-of-day metering, TVA pays 3.2 cents/kwh. Producers of more than 100kw with time-of-day metering are paid 4.49 cents/kwh during on-peak hours and 2.8 cents/kwh, off-peak.	Harold Usher, TVA, (615) 751-0011.
Texas Public Utility Commission	Final order. Utilities must file purchased power rates with PUC by June 30. Rates should be based on avoided cost. Prior to June 30, rates may be based on average fuel cost. One major utility and a few cooperatives have had rates approved.	**Houston Lighting & Power Co.** (approved): For producers of up to 5,000 kw, rate is current month's fuel cost adjustment multiplied by figure ranging from 1.01 to 1.64 depending on time, season and whether power is from qualifying facility or not. Larger producers have option of using same rate or rate based on an hourly avoided cost formula.	Mike Williams, PUC, (512)458-0202.
Utah Public Service Commission	Temporary rates established April 1981 still in effect. Final determination by PSC pending.	**Utah Power and Light:** 2.2 cents/kwh for units up to 1 mw (or 100 kw for hydro). For larger units, rates are negotiable on case-by-cast basis up to 3.5 cents/kwh.	Douglas Kirk, PSC, (801) 533,3247.
Vermont Public Service Board	Final rules adapted June 1981. Rates will be reviewed annually.	For cogenerators who supply electricity on a 24-hour basis, flat rate is 7.8 cents/kwh; for electricity supplied between 8 p.m. and 8 a.m., 6.6 cents/kwh; between 8 a.m. and 8 p.m., 9 cents/kwh.	Peter Zamore, PSB, (802)-828-2880.

Virginia State Corporation Commission	In effect.	Differ according to avoided costs of six utility companies in state. Rate change expected in May when utilities deliver new cost figures. **Virginia Electric and Power Co. (VEPCO)**: For July, August, September, December, January and February, on-peak (10 a.m. to 10 p.m.) is 3.815 cents/kwh and off-peak, 1.815 cents/kwh. For remaining months, on-peak is 3.441 cents/kwh and off-peak, 1.815 cents/kwh. **A&N Electrical Cooperative**: On-peak (8 a.m. to 9 p.m.) is 3.75 cents/kwh and off-peak, 2.7 cents/kwh. **Appalachian Power Co.**'s rates are determined by equation formula. Virginia has 29 cooperatives, or smaller utilities, which have base rate of 2.413 cents/kwh for all cogenerators.	William Stevens, SCC, (804) 786-4932.
Washington Utilities and Transportation Commission	UTC approved rates for cogenerators producing 100 kw and less.	**Washington Water Power Co.**: 2.7 cents/kwh. **Puget Sound Power and Light Co.**: 1.90 cents/kwh May through September, and 3.96 cents/kwh October through March. **Pacific Power and Light**: 2.795 cents/kwh.	Dick Bostwick, UTC, (206) 753-1096.
West Virginia Public Service Commission	Final tariffs for cogenerators producing 100 kw or less pending. Tariffs for larger producers deferred, pending final federal ruling on PURPA constitutionality.	Not available.	Rich Hitt, PSC, (304) 348-2174.
Wisconsin Public Service Commission	Temporary rates in effect. Hearings under way for final order on rate revision cases.	**Lake Superior District Power Co.**: 1.9 cents/kwh for all power. **Madison Gas and Electric Co.**: Winter on-peak, 2.22 cents/kwh; off-peak 1.5 cents/kwh; summer on-peak, 2.75 cents/kwh; off-peak 1.50 cents/kwh. **Northern States Power Co.**: First 20 kw produced monthly, on-peak 1.84 cents/kwh; off-peak 1.14 cents/kwh; 21-500 kw on-peak, 1.84 cents/kwh; off-peak, 1.14 cents/kwh; 21-500 kw, on-peak, 1.60 cents/kwh; off-peak 1.14 cents/kwh. **Wisconsin Electric Co.**: Firm on-peak, 3.55 cents/kwh; off-peak, 1.45 cents/kwh; non-firm on-peak, 2.9 cents/kwh; off-peak, 1.45 cents/kwh. **Wisconsin Power and Light Co.**: Off-peak, 1.75 cents/kwh; on-peak, 4.8 cents/kwh. **Wisconsin Public Service Corp.**: Non-firm on-peak, 1.85 cents/kwh; off-peak 1.32 cents/kwh. Firm prices negotiated per cogenerator.	Jennifer Fagen, PSC, (608) 266-5620.
Wyoming Public Service Commission	Final rates established but could be changed based on Energy Department-funded study of innovative, non-discriminatory cogeneration and small power producer buyback rates. Study expected to be completed in September 1982.	Established for 26 different utilities. (PSC refused to release rates over the phone.)	Dave Walker, PSC, (307) 777-7427.

TESTIMONY BEFORE THE SENATE ENERGY REGULATORY SUBCOMMITTEE

Hearings on S. 1885

Submitted by:

C. WILLIAM CARTER

Vice President - Operations
Long Lake Energy Corporation
330 Madison Avenue
New York, New York 10017

We would like to thank the Chairman and members of the Energy Regulation Subcommittee for the opportunity to submit the views of Long Lake Energy Corporation concerning S.1885. We are strongly opposed to any change in utility ownership in cogeneration and small power production facilities. We believe S.1885 would have a devastating impact on the future of not only renewable energy resource development but also the new companies that are the key to timely, efficient development of these resources.

Long Lake Energy Corporation is a private firm developing small-scale hydroelectric projects in New York State and Pennsylvania. We have played a catalytic role in the development of hydroelectric energy in New York State. In the past twelve months, we have filed 39 permits and 19 licenses. The Federal Energy Regulatory Commission (FERC) has issued two licenses to us and we hope to receive several more in the near future. From our experience in developing small scale hydro projects, we know that tilting the 50% ownership rule in favor of the utilities or their holding companies would undermine our company as well as other small power producers.

The original purpose of the 50% ownership limitation for utilities and their affiliates was to open up the utilities' monopoly on power production ownership. Congress recognized that the most efficient and rapid development of renewable energy resources would be achieved by encouraging private industry with financial incentives and, equally important, with access to the power production marketplace. In the case of hydro, this introduced competitive marketplace economics into an area of power production neglected by the utilities. As expected, small power producers responded enthusiastically to the opportunities created by PURPA and other energy legislation. The result has been an explosion of development activity in hydroelectric power and other renewable energy technologies.

The 50% ownership limitation is particularly critical in the case of hydro power. The small hydro power producers are an infant industry. Many license and permit filings have been made. Few have been awarded and the most critical steps lie ahead: securing necessary power purchase contracts, using these to obtain financing and actually building and operating the plants. Many companies such as ours are just reaching a point of dealing with the investment community to obtain long-term financing. The banking community has gradually educated itself about making investments in developing renewable energy. Just at a point when the investment community understands, weakening small producers ability to secure rights to sites would be disastrous. It is difficult enough now for small power producers to compete with utilities on license filings and then turn around and negotiate power purchase contracts.

The 50% rule provides a powerful incentive for utilities to work with small power producers if they wish to obtain the full benefit of tax incentives and PURPA rates from their development efforts. 50/50 means utilities do not have the automatic upper hand, which any further tilting of the formula would produce. A change in the utility ownership rule weakens the new small power producers. They are already in a difficult bargaining position with a monopoly that controls most of the industry's production, transmission and distribution.

Another basic issue is: who do you believe will actually have the motivation to develop renewables? Increasing utility ownership could provide a significant incentive for the utilities to lock up development rights for projects regardless of their real capital investment intentions. At a minimum, the utilities are much more capable of dragging out a dispute, knowing they can outlast a new small company for which time is a much more critical factor.

We urge this Committee not to change the 50% utility ownership rule for qualifying facilities. The impact this would have on hydro development would be particularly devastating. It would place utilities back in full control of the courtry's hydro power production, reduce the extent and speed of real development of these resources, and seriously discourage venture capital firms from investing in the new companies that have led the charge in the past few years by taking Congress at its word that competition would replace monopoly in this sector of the power generation industry. At a time when Congress and the Administration want to encourage the growth of vital new industries, it is bad public policy to pull the rug out from under the new companies that have taken entrepreneural risks and clearly demonstrated interest and ability to produce energy from renewable energy resources.

By leaving the ownership rule unchanged and making FERC's recently vacated rules on avoided costs and interconnection into law, small power producers will be able to move forward rapidly with renewable energy development.

If you have any questions, please feel free to contact me.

Thank you.

POTSDAM PAPER CORPORATION
POTSDAM, NEW YORK 13676 (315) 265-4000

Malcolm M. Preston
Executive Vice President

April 16, 1982

Honorable Gordon J. Humphrey
Chairman
Senate Energy Subcommittee
UNITED STATES SENATE
Washington, DC 20510

Dear Sir:

The purpose of this letter, which is prepared in conjunction with the appearance before your committee of the American Paper Institute, is to apprise you and the Energy Committee of the difficulties our company has experienced in negotiating an electric sales contract with our utility, Niagara Mohawk Power Corporation, to enable redevelopment of our two hydroelectric dams. In our opinion, both the Section 210 of the PURPA law enacted by Congress in 1978 and enabling legislation passed in New York State in 1981 have been ineffective in accomplishing their intended objective, that of providing an inducement for the redevelopment of alternative energy sources, specifically as this legislation relates to our project.

Potsdam Paper Corporation is a small manufacturer of fine paper located on the Racquette River in Potsdam, St. Lawrence County, New York. The company came into existence in 1977 when a closed paper mill was purchased as an entrepreneural venture from its previous owners. Wilbur W. Krueger, President, and myself are the principal owner/stockholders of the corporation. Financially, the company has sales of approximately $25 million a year and, because it is a new venture, it has modest equity and is highly leveraged. The company is marginally profitable at the present time.

Potsdam Paper Corporation has two run of the river licensed hydroelectric dams on the Racquette River which were acquired with the mill property. These two dams are currently producing approximately 1,000 kilowatts of electric power on an intermittent basis, limping along with 80 year old equipment. An engineering study by the firm of Ayres, Lewis, Norris, and May, Inc, of Ann Arbor, Michigan, projects the potential capacity of the two twenty-foot dams at 5,600 kilowatts. Based on river flow studies, the potential generating capacity of the facilities conservatively averages 49 million kilowatt hours annually, the equivalent of 1,200,000 gallons of oil.

Based on the engineering study, the company obtained a financing proposal from the investment firm of Smith, Barney, Harris, Upham & Co., Inc. That proposal confirms an ability to finance the project provided a firm, long term contract can be obtained for the sale of the electricity as provided by PURPA and enabling state legislation. The project would not be financeable without such a contract because of Potsdam Paper Corporation's limited resources.

Based on the above, we initiated negotiations for such a contract with Niagara Mohawk Power Corporation in the fall of 1981. After several preliminary discussions, we met on December 9, 1982, with representatives of that corporation, who verbally agreed to give us such a contract, with the only remaining question being the applicability of the state legislation to all of the power or the incremental power produced by the renovated facility. At Niagara Mohawk's request, our company initiated an inquiry to the New York State Public Service Commission for a ruling on this one matter.

On January 9, 1982 we received a draft contract from Niagara Mohawk which, as stated in their cover letter, was "...intented to be short term.......until the new generating facilities are operating....." and further stating that "It will be necessary that we enter into a new agreement once the new facilities are in operation." This was clearly not the long term contract requested by us, agreed to at our December 9th meeting, and clearly intended by both federal and state law. In fact, the contract received is essentially the same as we now have for dump power, with only minor legal modifications. Follow up requests and letters have failed to produce meaningful negotiations for a contract. Although we have another meeting scheduled with Niagara Mohawk later this month, discussions with the New York State Public Service Commission staff and others give us little cause for optimism. It is our contention that Niagara Moawhk, by both delaying its response to our request and failing to provide the obviously needed long term contract, is deliberately trying to avoid the intent of both the federal and state legislation.

As of this date, the Public Service Commission has not yet ruled on our request, although we now expect a ruling on April 21st. Approximately a four month delay in this ruling was caused by the intervention of Niagara Mohawk.

There is an interesting side note. Concurrently with the difficulty imposed on negotiations by Niagara Mohawk, we have had several approaches from Hydra-Co Enterprises, Inc, a wholly-owned subsidiary of that company, to financially participate in and assist us with our project.

During the past several weeks we have been in contact with a number of other developers, as well as the Public Service Commission, and we can find no one who has been able to obtain a long term contract with Niagara Mohawk under the federal and state laws. In the course of our conversations with other developers, we have heard some horror stories about negotiations which make our own problem seem small. Because of the considerable interest in alternate energy and small hydro development in our area, we are in the process of forming a coalition to try and deal more effectively with the utility on these problems. It should be noted that most of the developers are small companies like ours with limited resources. The thrust of this coalition is to get the utility to obey the law.

In conclusion, our company has a viable project to generate electricity with a direct impact, albeit small, on our country's dependence on foreign oil. We can produce that electricity at a cost that will be competitive with other incremental energy sources from the outset and become more competitive in the future. We are, however, at this juncture, unable to proceed with the project because of our inability to deal responsibly with Niagara Mohawk, even though they are required to do so by law. The PURPA legislation now approaches four years old. If our case is typical [and we have good reason to believe it is] we can only conclude that the utilities have effectively negated the law's intended impact.

We hope the above will be useful to your committee in its deliberations and would be please to provide the committee or its staff with any further information we can.

Yours truly,

POTSDAM PAPER CORPORATION

Malcolm M. Preston
Executive Vice President

MMP/ljl

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PUBLIC UTILITY DISTRICT NO. 1 OF OKANOGAN COUNTY

June 4, 1982

The Honorable Henry M. Jackson
United States Senator
Senate Office Building
Washington, D.C. 20510

Dear Senator:

We have recently been informed that the Senate Energy Committee has held hearings on S.1966,a bill to repeal Sec. 116 of the Public Utilities Regulatory Policy Act (PURPA). Okanogan County P.U.D. supports this bill and further recommends the Senate consider repealing the entire Title I of PURPA. We feel Title I requires needless reporting to the Department of Energy, and that our customers receive no benefits from this reporting requirement.

This District has always held public hearings on its rates and policies. We do not feel that reporting the results of these hearings to the DOE serves any constructive purpose.

As you are probably aware, we are in a period of rapidly escalating electric rates. We feel it is extremely imperative to monitor costs at both the local and federal levels. Accordingly, we recommend you support S.1966 and consider amending this bill to include the entire Title I program of PURPA.

Sincerely,

Harlan Warner

Harlan Warner
Manager

bh

PUD
2320 California St., Everett, Washington 98201 258-8211
Mailing Address: P. O. Box 1107, Everett, Washington 98206

June 22, 1982

The Honorable Henry M. Jackson
United States Senate
137 Russell Senate Office Building
Washington, D. C. 20510

RE: S. 1966 - PURPA Section 116 Reporting Requirements

Dear Senator ~~Jackson~~:

The Senate Energy Committee has recently conducted a hearing on S. 1966, which would repeal PURPA section 116. That section of PURPA requires utilities to file annual reports with the Department of Energy on the results of their hearings on the PURPA standards contained in sections 111 and 114.

The District held hearings on these matters in the summer of 1981, and later made determinations pursuant to those hearings. Notice of the District's action and a copy of the Resolution acting on the standards was filed with the Department of Energy, as required. PURPA sections 112 and 113 require the utilities to consider certain rates and standards. Adoption and implementation of such rates and standards is not required by PURPA.

PURPA section 116 requires utilities to report on rates and standards which were not required to be adopted or implemented. One of the purposes of the Act contained in section 101 is

> ...[To] encourage...(3) equitable rates to electric consumers. (emphasis added)

The requirement that public hearings be conducted on the rates and standards recommended in the Act encourages implementation of any such rates and standards adopted by a utility - reporting adds nothing.

The Honorable Henry M. Jackson
June 22, 1982
Page 2

This utility supports the proposal to repeal section 116 as contained in S. 1966. No demand for such reports have been made by any of our customers. Although reporting under section 116 is not especially burdensome, it does seem useless and an unproductive expenditure of time and effort. Such a report is more likely to gather dust in the Department of Energy's archives that be of any real value to the electric consumer.

I trust that these comments will be useful to you in your consideration of S. 1966. Please do not hesitate to contact me if you desire any further information on this matter.

Sincerely,

W. G. Hulbert, Jr.
Manager

/djp